Corrosion

Official Publication

NATIONAL ASSOCIATION OF CORROSION ENGINEERS

Vol. 12 MAY, 1956 No. 5

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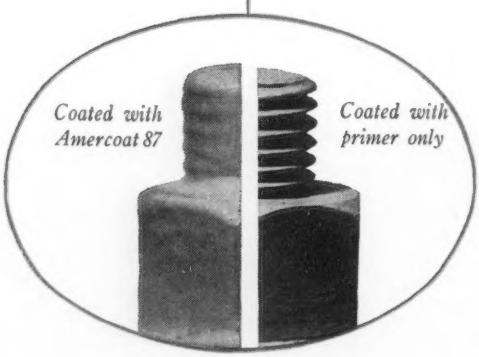

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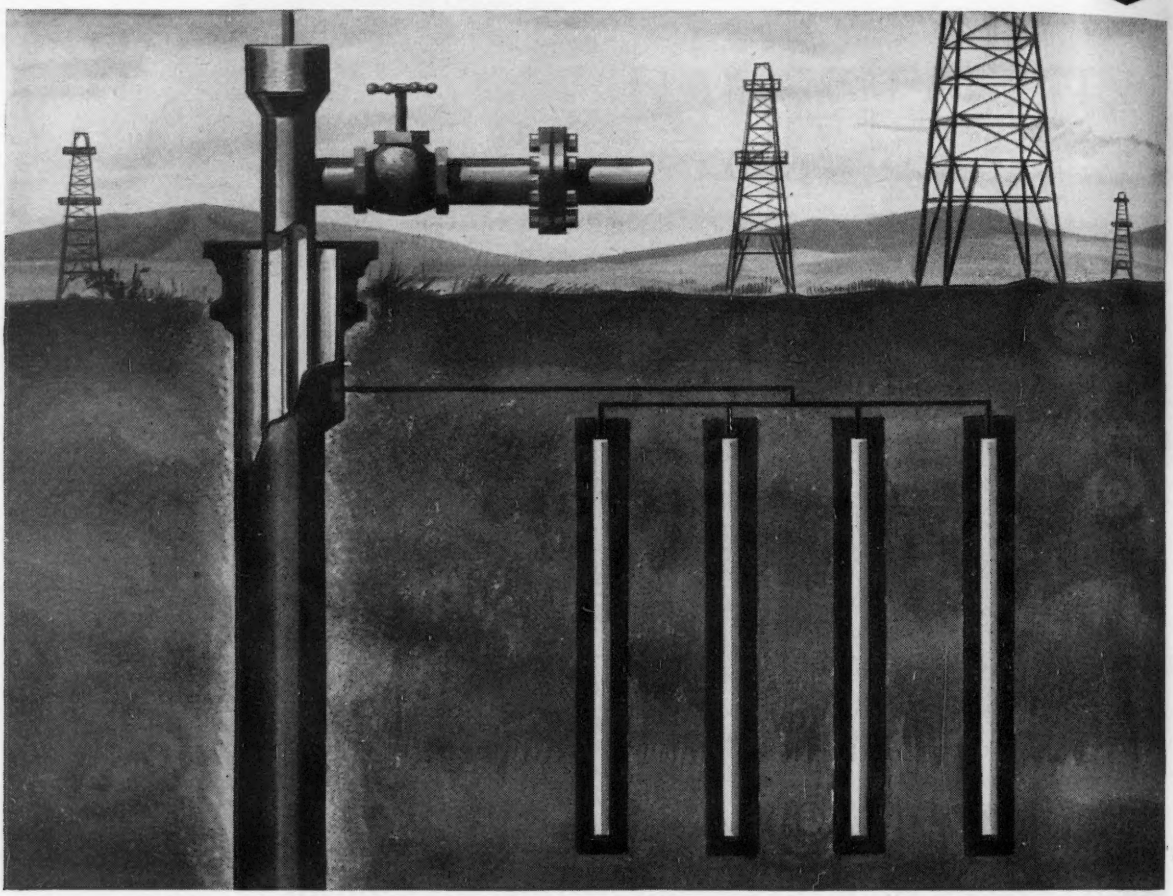

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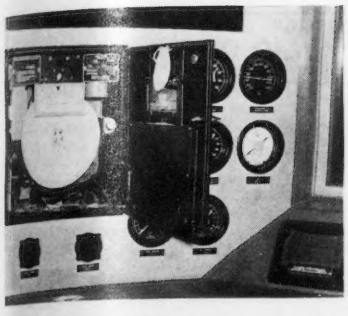

THIS MONTH'S COVER—A porous cotton bag containing Shell Chemical Company's vapor phase inhibitor is shown hanging from the door of a cabinet containing electrical instruments at the Michoud Ordnance Plant at New Orleans. Al-Con Chemical Co., New Orleans, supplied the inhibitor used to put the plant on standby basis. The crystals vaporize slowly in the cabinet and protect the instrument against rust.

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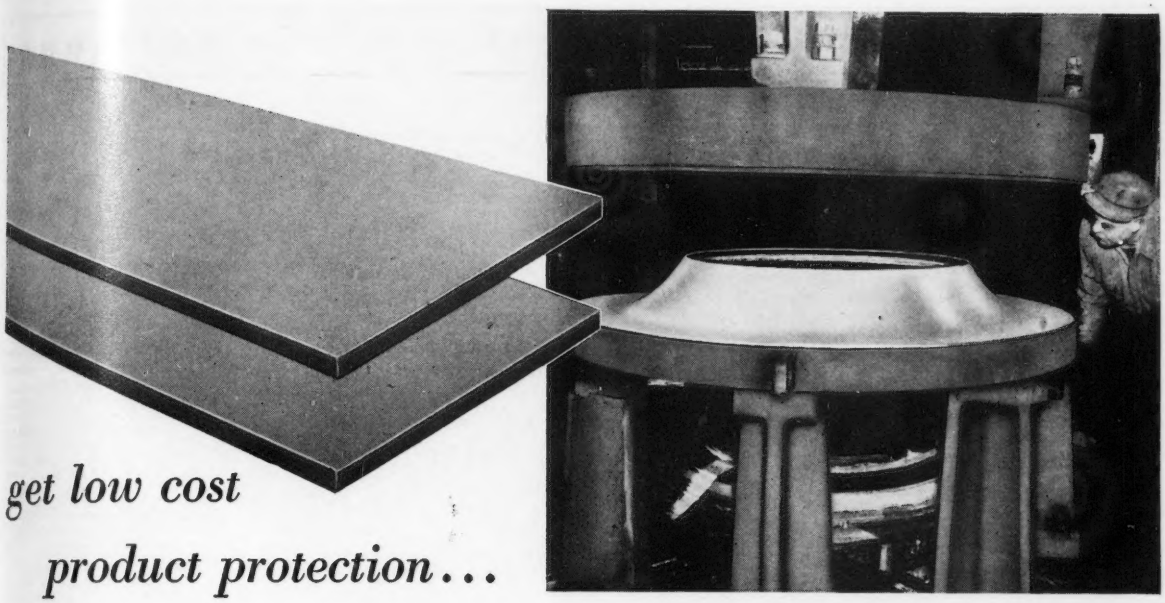

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W. H. Burton, Vice Chairman, General Chemical Division, Allied Chemical & Dye Corp., Camden, New Jersey.

• T-5A-6 HF Corrosion

T. L. Hoffman, Chairman, Phillips Petroleum Co., Atomic Energy Div., Box 1259, Idaho Falls, Idaho.

T-5B High Temperature Corrosion

John Halbig, Chairman, Armco Steel Corp., Middletown, Ohio.
E. N. Skinner, Vice Chairman, The International Nickel Co., Inc., 67 Wall St., New York, N. Y.

• T-5B-2 Sulfide Corrosion at High Temperatures and Pressures in the Petroleum Industry

M. E. Holmberg, Chairman, 4101 San Jacinto St., Houston, Texas.

• T-5B-3 Oil Ash Corrosion

R. T. Foley, Chairman, General Electric Co., Schenectady, New York.

• T-5B-5 Corrosion by Molten Salts and Metals

W. D. Manly, Chairman, Oak Ridge National Laboratory, Oak Ridge, Tennessee.

T-5C Corrosion by Cooling Waters

• T-5C-1 Corrosion by Cooling Waters (South Central Region)

A. S. Krisher, Chairman, Monsanto Chemical Co., Texas City, Texas
C. P. Dillon, Vice Chairman, Carbide & Carbon Chemicals Co., Texas City, Texas.
J. L. Weis, Secretary, Diamond Alkali Company, Box 686, Pasadena, Texas.

T-5D Plastic Materials of Construction

S. W. McIlrath, Chairman, 151 East 214th St., Euclid, Ohio.
J. S. McBride, Secretary, Owens-Corning Fiberglas Corp., 598 Madison Avenue, New York 22, New York.

• T-5D-1 Questionnaires

S. W. McIlrath, Chairman, 151 E. 214th Street, Euclid 23, Ohio.

• T-5D-2 Inorganic Acids

Edward Layman, Chairman, Diamond Alkali Company, P. O. Box 686, Pasadena, Texas.
R. L. Hughes, Vice Chairman, Spencer Chemical Co., 1231 Woodswether Rd., Kansas City, Missouri.
J. F. Malone, Secretary, B. F. Goodrich Chemical Co., 2060 East Ninth Street, Cleveland 15, Ohio.

• T-5D-3 Inorganic Alkalies

Peter Kimen, Chairman, Champion Paper & Fibre Co., Box 872, Pasadena, Texas.
L. B. Connelly, Secretary, Eastman Chemical Products Company, 704 Texas National Bank Building, Houston 2, Texas.

• T-5D-4 Gases

Beaumont Thomas, Chairman, Stebbins Eng. & Mfg. Co., Eastern Blvd., Watertown, New York.
J. L. Forse, Vice Chairman, Dow Chemical Company, Plastics Technical Service, Midland, Michigan.
William Eakins, Secretary, Chemical Corporation, Platank Division, West Warren, Massachusetts.

• T-5D-5 Water and Salt Solutions

Paul Elliott, Chairman, Naugatuck Chemical Company, Kralastic Development, Naugatuck, Conn.

• T-5D-6 Organic Chemicals

R. E. Gackenbach, Chairman, American Cyanamid Company, Calco Chemical Division, Bound Brook, New Jersey.
B. B. Pusey, Vice Chairman, Bakelite Co., Div. of U.C.C., Bound Brook, New Jersey.
Wade Wolfe, Jr., Secretary, 73 Ermann Drive, Buffalo 17, New York.

• T-5D-7 Engineering Design

O. H. Fenner, Chairman, Monsanto Chemical Company, 1700 South Second Street, St. Louis 4, Missouri.
K. A. Phillips, Vice Chairman, American Zinc, Lead & Smelting Co., P. O. Box 495, East St. Louis, Illinois.
W. B. Meyer, Secretary, St. Louis Metallizing Co., 625 South Sarah, St. Louis 10, Missouri.

• T-5D-8 Methods and Criteria for Evaluating Plastics in Chemical Environment

R. F. Clarkson, Chairman, Olin Mathieson Chemical Corp., Mathieson Building, Baltimore, Md.
R. Lembcke, Secretary, Cities Service Res. & Dev. Co., 920 East Third, Tulsa 3, Oklahoma.

T-5E Stress Corrosion Cracking of Austenitic Stainless Steel

L. Miller Rogers, Chairman, Union Carbide & Carbon Chemical Co., Box 471, Texas City, Texas.

T-6 Protective Coatings

L. L. Whiteneck, Chairman, Long Beach Harbor Dept., 1333 El Embarcadero, Long Beach, California.
L. S. Van Delinder, Vice Chairman, Carbide & Carbon Chemicals, Co., South Charleston, West Va.

T-6A Organic Coatings and Linings for Resistance to Chemical Corrosion

R. McFarland, Jr., Chairman, Hills-McCanna Co., 3025 N. W. Ave., Chicago 18, Illinois.
C. G. Munger, Vice Chairman, Amercoat Corp., 4809 Firestone Blvd., South Gate, Calif.
L. A. Ferris, Secretary, E. I. DuPont de Nemours & Co., Inc., Polychemicals Dept., Wilmington, Delaware.

• T-6A-1 Heavy Linings

H. C. Klein, Chairman, B. F. Goodrich Co., Cuyahoga Falls, Ohio.

• T-6-2 Vinyl Coatings

K. Tator, Chairman, 2020 Montour Street, Coraopolis, Pa.

• T-6A-3 Vinylidene Chloride Polymers

R. L. Brown, Chairman, The Dow Chemical Co., Midland, Mich.

• T-6A-4 Phenolics

F. Baskett, Chairman, 4334 Ella Blvd., Houston, Texas.

• T-6A-5 Polyethylene

L. S. Van Delinder, Chairman, Carbide & Carbon Chemicals Co., South Charleston, West Va.

• T-6A-6 Rubber and Elastomers

H. C. Klein, Chairman, B. F. Goodrich Co., Cuyahoga Falls, Ohio.

• T-6A-7 Silicones

R. McFarland, Jr., Chairman, Hills-McCanna Co., 3025 N. Western Ave., Chicago, Ill.

• T-6A-8 Methyacrylates

L. S. Van Delinder, Chairman, Carbide & Carbon Chemicals Co., South Charleston, West Va.

• T-6A-9 Furanes

F. Baskett, Chairman, 4334 Ella Blvd., Houston, Texas.

• T-6A-10 Polyesters

R. R. Pierce, Chairman, Pennsylvania Salt Mfg. Co., 3 Penn Center Plaza, Philadelphia, Pa.

• T-6A-11 Epoxys

C. G. Munger, Chairman, Amercoat Corp., 4809 Firestone Blvd., South Gate, Calif.

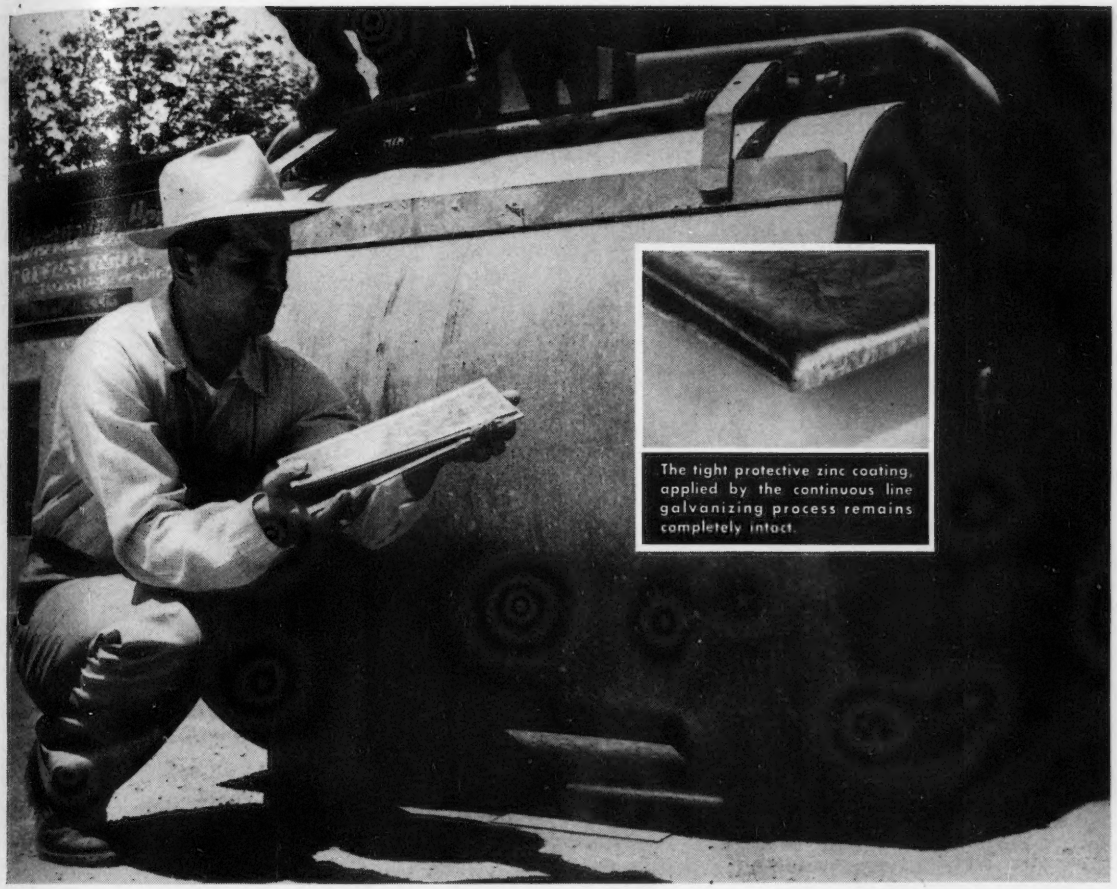
• T-6A-12 Fluorocarbons

L. A. Ferris, Chairman, E. I. Du Pont de Nemours & Co., Inc., Wilmington, Delaware.

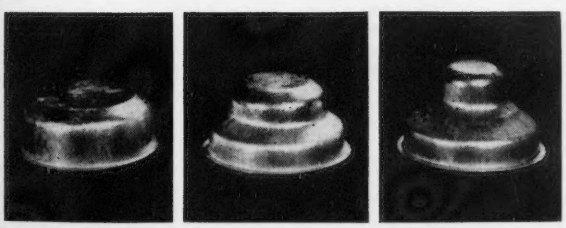
T-6B Protective Coatings for Resistance to Atmospheric Corrosion

Howard C. Dick, Chairman, Products Research Service, Inc., Box 6116, New Orleans, Louisiana.

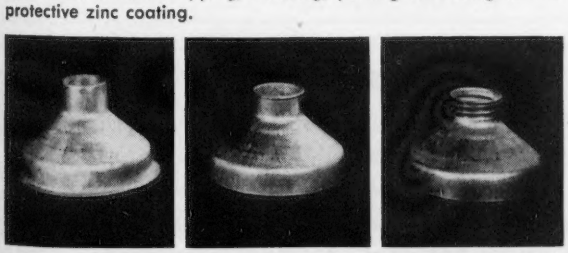
(Continued on Page 8)



THE SHAPE OF THINGS TO COME



AN EXAMPLE: This sprinkling can rosette was formerly made of black plate and then electroplated to provide the necessary rust-proofing; it is now produced from flat, galvanized stock in six operations without chipping, cracking, peeling or flaking of the protective zinc coating.



Photos of rosette, courtesy WHEELING STEEL CORP.

The progress that has been made in the United States to take full advantage of the unexcelled qualities of zinc as a protective metal is dramatically illustrated here. Many products made of galvanized sheet steel are pressed into shape by terrific force. But if a galvanized sheet can be flattened into a *double fold* under the crushing weight of a road roller without failure of the protective zinc coating, it is obvious that it will withstand equally well the severest drawing and forming operation.

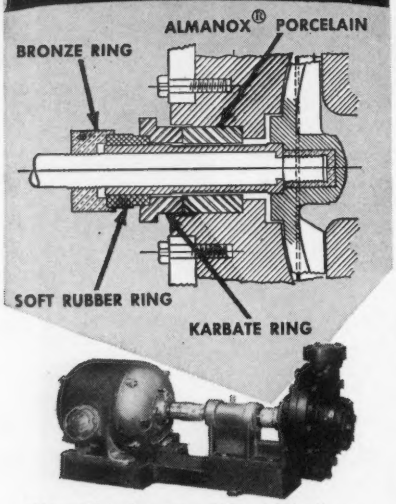
The improved properties of today's continuous line products has led to an enormous increase in their consumption. The zinc coating being as ductile as the base metal, anything that can be made of steel sheets, can now be made of galvanized sheet.

ST. JOSEPH LEAD COMPANY
250 PARK AVENUE, NEW YORK 17, N. Y.

HIGH GRADE
INTERMEDIATE
PRIME WESTERN

ST. JOE *electrothermic* ZINC

It's NEW...
Improved Seal on... Hard Rubber Pumps for Chemical Solutions



How This Improved Seal Works

New mechanical seal on all Luzerne Pumps is made by using a revolving karbate ring against a stationary almanox® porcelain ring. This permits a rubber covering on the metal shaft and eliminates usual packing troubles due to friction and leaking of conventional packing.

® Frenchtown Porcelain Co. Trade Mark

OTHER FEATURES

- Safely handles corrosive solutions
- Standardized parts for field repair
- Available in natural hard rubber or Buna-N synthetic rubber compounds to handle temperatures up to 225° F.

SPECIFICATIONS

Style A — Open impeller pump — 140 gallons per minute at 90 foot head maximum.

Style B — Open or closed impeller pump — 115 gallons per minute at 68 foot head maximum.

2" — Suction 1½" — Discharge

Write for complete information or contact our sales representative nearest you.

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565 West Washington St.
Chicago 6, Ill.

R. C. FOLTZ COMPANY
P. O. Box 13313
Houston 19, Texas

Directory of Technical Committees

(Continued From Page 6)

T-6C Protective Coatings for Resistance to Marine Corrosion

Raymond P. Devoluy, Chairman, The Glidden Co., Room 1310, 52 Vanderbilt Avenue, New York 17, New York.

R. F. Daw, Vice Chairman, The Texas Co., 135 East 42nd St., New York 17, New York.

T-6E Protective Coatings in Petroleum Production

F. T. Rice, Chairman, The Pure Oil Co., 35 E. Wacker Drive, Chicago, Ill.

T-6G Surface Preparation for Organic Coatings

S. E. Jack, Chairman, Aluminium Laboratories, Ltd., Box 84, Kingston, Ontario, Canada.

S. C. Frye, Vice Chairman, Research Dept., Bethlehem Steel Co., Bethlehem, Pa.

T-6H Glass Linings and Vitreous Enamels

G. H. McIntyre, Chairman, Ferro-Enamel Corporation, 4150 East 56th Street, Cleveland, Ohio.

T-6K Corrosion Resistant Construction With Masonry and Allied Materials

L. R. Honnaker, Chairman, E. I. Du Pont de Nemours Company, Inc., Eng. Dept., 13W10 Louviers Bldg., Wilmington, Del.

George P. Gabriel, Vice Chairman, Atlas Mineral Products Company, Mertztown, Pa.

T-6R Protective Coatings Research

Joseph Bigos, Chairman, Steel Structures Painting Council, Mellon Inst., 4400 Fifth Ave., Pittsburgh 13, Pa.

T-7 Underground Corrosion Coordinating Committee

J. M. Fouts, Chairman, New York Telephone Company, 63 E. Delavan Avenue, Buffalo, New York.

C. A. Erickson, Jr., Vice Chairman, The Peoples Natural Gas Company, 140 Stanwix Street, Pittsburgh, Pa.

T-7A Northeast Region Underground Corrosion Coordinating Committee

C. A. Erickson, Jr., Chairman, The Peoples Natural Gas Company, 140 Stanwix Street, Pittsburgh, Pa.

T-7B North Central Region Underground Corrosion Coordinating Committee

(Officers not yet selected)

T-7C Southeast Region Underground Corrosion Coordinating Committee

(Officers not yet selected)

T-7D South Central Region Underground Corrosion Coordinating Committee

(Officers not yet selected)

T-7E Western Region Underground Corrosion Coordinating Committee

(Officers not yet selected)

T-7F Canadian Region Underground Corrosion Coordinating Committee

(Officers not yet selected)

Regional and Sectional Officers—Changes

• Kanawha Valley Section

Jack Bates, Chairman; Carbide & Carbon Chemicals Company, 437 MacCorkle Avenue, South Charleston, West Va.

George Klohr, Vice-Chairman; E. I. du Pont De Nemours Co., P. O. Box 993, Charleston 24, West V.

George Walther, Secretary; Westvaco Chemical Div. Food Machinery & Chemical Corp., P. O. Box 8127, So. Charleston, West Va.

Fred Lloyd, Treasurer; United Fuel Gas Co., 1033 Quarrier St., Charleston 25, West Va.

• Los Angeles Section

John R. Brown, Chairman; 3525 West 74th Place, Inglewood, Cal

Dave J. Colyer, Jr., Vice-Chairman; The Duriron Company, Inc., 6903 Rita Avenue, Huntington Park, Cal.

Don Miller, Secretary-Treasurer; Southern California Gas Company, Box 3249, Terminal Annex, Los Angeles, Cal.

• Metropolitan New York Section

Nelson Ehinger, Secretary-Treasurer; Aluminum Company of America, 230 Park Avenue, New York, N. Y.

• Southwestern Ohio Section

Cliff Jones, Chairman; Cincinnati Gas & Electric Company, 2120 Dana Ave., Cincinati 7, Ohio

Sol Gleser, Vice-Chairman; A. M. Kinney, Inc., 2905 Vernon Place, Cincinnati 19, Ohio

William Hare, Secretary; Hare Equipment, 1720 Section Road, Cincinnati 37, Ohio

R. Leonard Wood, Treasurer; Cincinnati Gas & Electric Company, General Engineering Dept., P. O. Box 960, Cincinnati 1, Ohio

• Teche Section

George M. Harper, Jr., Trustee; Union Oil Company of California, Box 421, Abbeville, Louisiana

• West Kansas Section

Thomas A. Allan, Chairman; Cooperative Refinery Ass'n. P. O. Box 765, Great Bend, Kans.

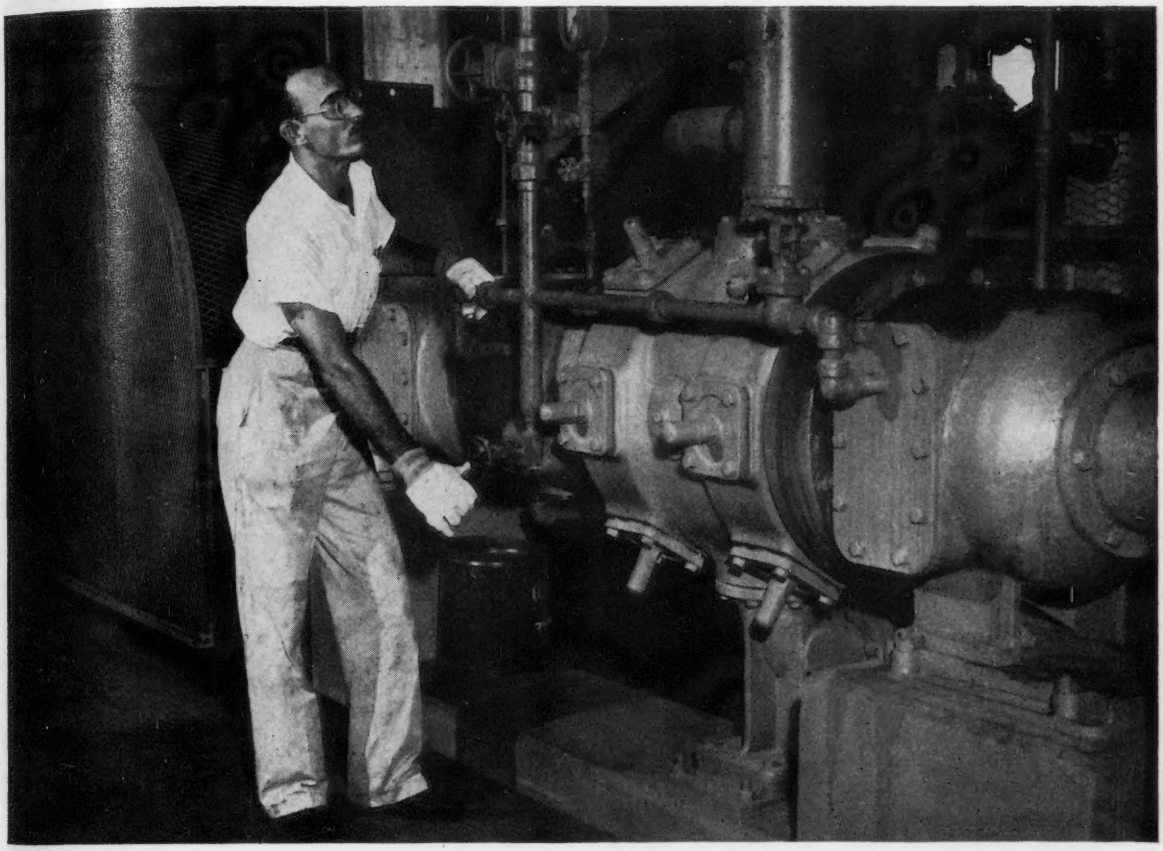
D. L. Peterson, Vice-Chairman; Cities Service Oil Company, P. O. Box 751, Great Bend, Kans.

J. P. Berry, Secretary-Treasurer; National Aluminate Corp., Box 1202, Hutchinson, Kans.

W. C. Koger, Trustee; Cities Service Oil Company, Cities Service Building, Bartlesville, Oklahoma.

BACK ISSUES OF VOLUME 11

Copies of back issues of Volume 11, January-December, 1955 are available except July. Persons who customarily bind all or parts of Corrosion and who lack issues to make the volume complete may get back copies at the following prices per copy, postpaid, remittance in advance: NACE members, 50 cents; Non-members, $1. An additional charge of 65 cents per package is made for mailings to addresses outside the United States, Canada and Mexico.

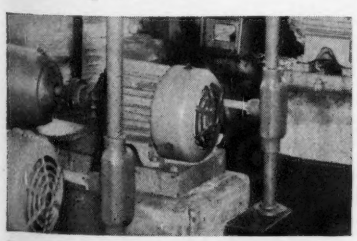


To ward off corrosion troubles in this chlorine compressor, contact parts are made of high-nickel alloys. Cylinder lines, packing cases, packing-ring springs, stuffing-box case and valve parts are Monel nickel-copper alloy. Other parts are heat-treated "K" Monel alloy or "S" Monel hard-grade nickel-copper cast alloy.

How Monel stalls trouble in dry-chlorine-handling equipment

In equipment handling dry chlorine, Monel* nickel-copper alloy establishes a twofold control over corrosion.

First, Monel resists dry chlorine and hydrogen chloride, even at temperatures up to 800°F.



Pumps transferring dry chlorinated hydrocarbons containing some chlorine and hydrogen chloride use mechanical seals of Monel alloy or Nickel. Nickel alloys protect against corrosives formed in humid atmosphere.

Second, Monel nickel-copper alloy is one of the few metals that resist low concentrations of hydrochloric acid formed when traces of moisture are present and temperature is below the dew-point — as often occurs in batch chlorinations.

Chlorine Institute standardizes on Monel

In shipping chlorine, it is standard practice to use valves with Monel alloy stems, seats and trim on most types of containers. The same corrosion-resisting alloy is used for chlorine compressor parts, pumps, orifice plates and other equipment that must preserve close tolerances.

When other factors enter in . . .

Look to other high-nickel alloys to take care of them. Inco's Development and Research Division will help you select materials to withstand specific conditions. And write for Inco's 28-page bulletin, "Resistance . . . to Corrosion by Hydrochloric Acid, Hydrogen Chloride, and Chlorine."

The International Nickel Company, Inc.
67 Wall Street New York 5, N. Y.

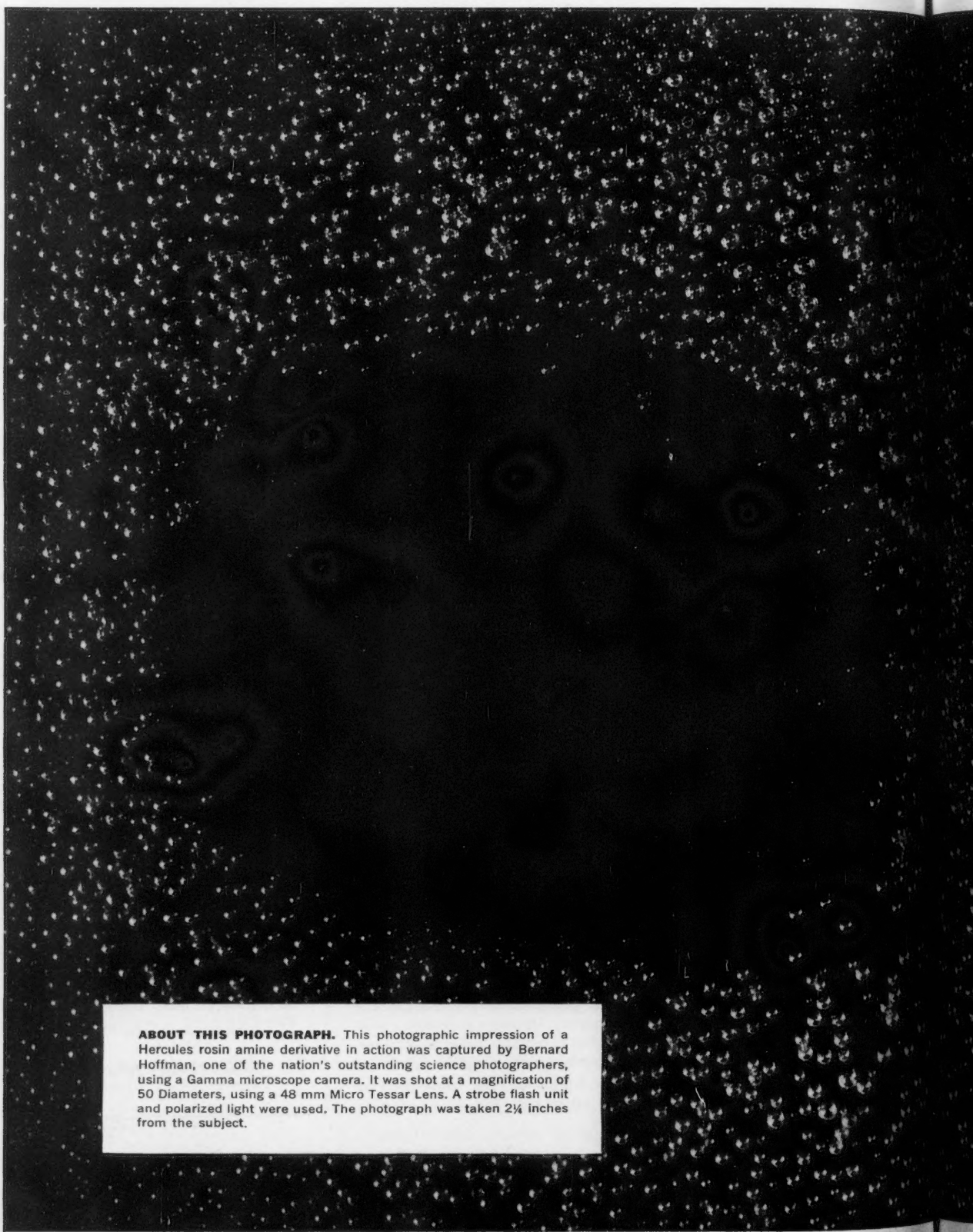
INCO TRADE MARK **Nickel Alloys**

*Registered trademark

Monel... for minimum maintenance

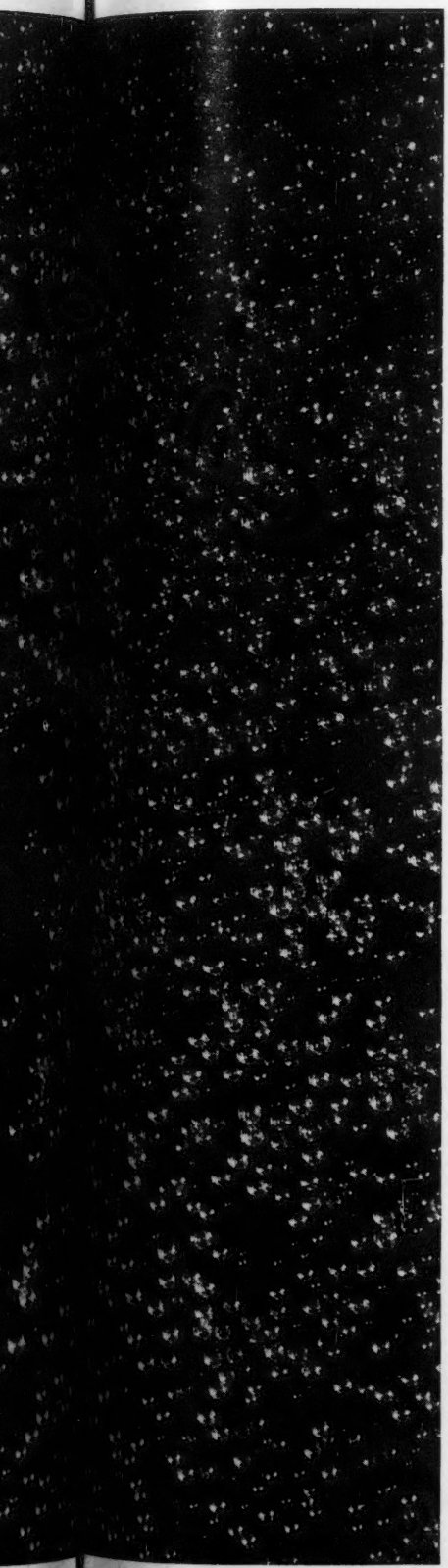
A New Look at Rosin Amine Through the Camera's Eye

(*one of a series*)



ABOUT THIS PHOTOGRAPH. This photographic impression of a Hercules rosin amine derivative in action was captured by Bernard Hoffman, one of the nation's outstanding science photographers, using a Gamma microscope camera. It was shot at a magnification of 50 Diameters, using a 48 mm Micro Tessar Lens. A strobe flash unit and polarized light were used. The photograph was taken 2¼ inches from the subject.

Adsorption to Metallic Surfaces



EXAMPLE: *Corrosion Inhibition*

This is a photograph of a safety island in a corrosive sea. A piece of mild steel has been completely covered with acid. The tiny bubbles being generated are the beginning of corrosive attack. The center area—free of bubbles—has been covered with a film of Rosin Amine D* derivative—proof of the inhibiting properties that have made this derivative an important weapon in the battle against corrosion.

Rosin amine derivatives adsorb to all types of metal surfaces. This results in an adsorbed film of closely-packed molecules that acts as a protective barrier between the metal surface and acidic fluids. Corrosion inhibition is one result of such a film.

The same property, however, is useful in anti-fouling agents for removal of solids such as salts, corrosion products, sludges from the metal surface. Preferential wetting of metal surfaces by either oil or water is another application of this property.

As chemical building blocks, Rosin Amine D and its derivatives offer opportunities to create new products and improve established ones. The wide range of basic properties they provide includes adsorption to siliceous surfaces, surface activity, and control of microbiological organisms. The amine derivatives are available in oil-soluble, water-soluble, and acid-soluble types.

Why not take a look at rosin amine. We'll be glad to send you detailed technical data.

**Hercules trademark*

HERCULES
ROSIN AMINE
DERIVATIVES

NA56-2

Pine Chemicals Division, Naval Stores Department
HERCULES POWDER COMPANY
INCORPORATED
999 King St., Wilmington 99, Del.

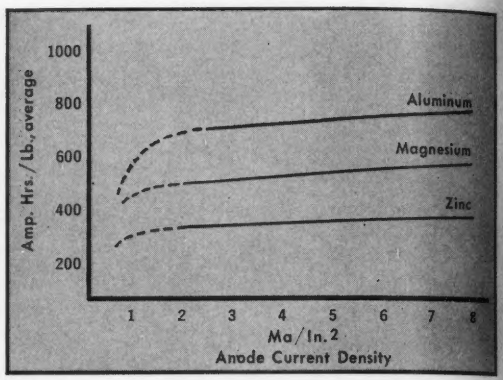
Here's why ALCOA'S NEW ALUMINUM ANODES give ships and marine structures more protection against sea-water corrosion at lower cost

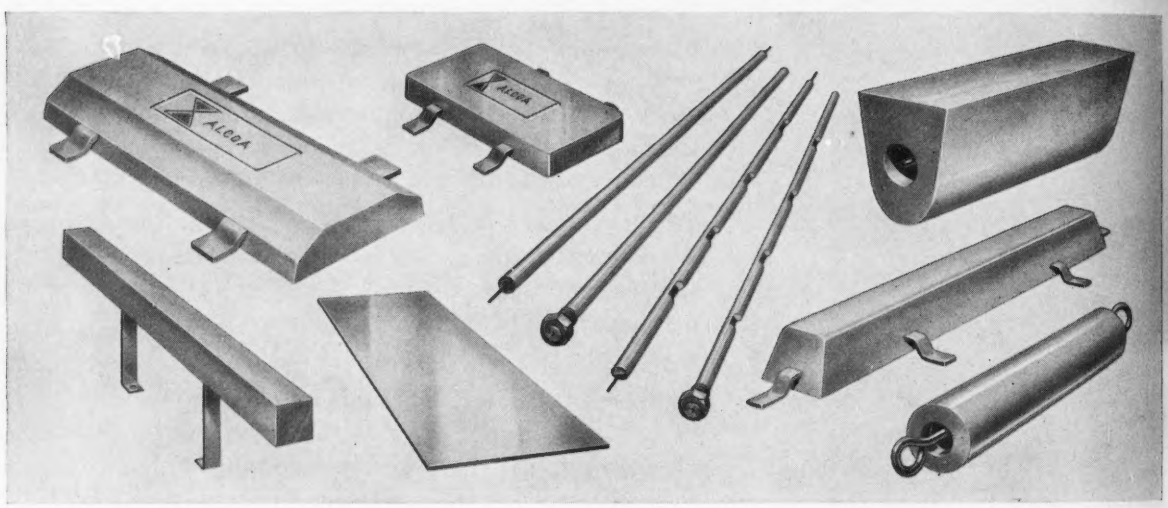
MORE AMPERE-HOURS PER POUND OF METAL

Aluminum anodes put out an average of 725 ampere-hours per pound. At current metal prices, this is a 44% better buy than with magnesium and 6% better than zinc.

NO SHIELDS OR RESISTORS

Not only do aluminum anodes put out more ampere-hours, they put them out at a safe rate so that shields or resistors are not needed. Damage to adjacent coatings is minimized—almost eliminated.





LONGER PROTECTION PER POUND

Aluminum anodes are nonpassivating . . . remain active. Installations can be designed for long-time service, cutting replacement costs. Continuous protection is provided during long away-from-drydock periods.

THE ALCOA HOUR
TELEVISION'S FINEST LIVE DRAMA
ALTERNATE SUNDAY EVENINGS

SHAPE AND SIZE FOR EVERY NEED

Alcoa's new line of marine anodes includes 8 basic types to cover every type of application: hulls, tanks, piers, "Texas Towers," condenser boxes and similar applications. Installation can be by means of bolts, welding or suspension. Designs provide for fast, easy installation at minimum cost. Available in many sizes . . . with pitch undercoating, cast-in cores, or as 1-inch utility plate.

WRITE FOR COMPLETE DATA

Aluminum Company of America
1670-E Alcoa Building, Pittsburgh 19, Pa.
Please send technical bulletin on *Alcoa Aluminum Anodes.*

Name_____

Company_____

Title_____

Address_____

City and State_____

ALCOA ALUMINUM ANODES
ALUMINUM COMPANY OF AMERICA

Your Guide to the Best in Aluminum Value

CAREY PIPELINE WRAPPING MATERIALS PROTECT THE BIGGEST "BIG INCH"!

Carey Offers Everything You Need In Pipeline Wrappings . . .

1. **CAREY GLASS.** Reinforces, toughens and hardens coatings to resist cold flow. Made of uniformly-drawn fibers, laid in a pattern scientifically proved to give maximum strength.

2. **CAREY ASBESTOS PIPELINE FELT.** Shields the reinforced coating against soil stress, pressure points and extreme temperatures. Developed as a result of 25 years of proved field experience.

3. **CAREY PIPELINE PADDING.** The original pipeline padding. Strong and flexible, it molds easily to the shape of the pipe without grooving or weakening.

For positive protection, specify the complete line of laboratory-tested, job-proved Carey pipeline protection products. Ask your Carey Sales Engineer for full data or write us at Cincinnati.

Miles and miles of 36 inch pipeline winding across ten states—carrying 130 million cubic feet of gas a day—natural gas from Texas to heat the homes of New York City. That's The Transcontinental Gas Pipe Line Corporation's "Super-Inch"! A big, tough pipeline job requiring positive protection.

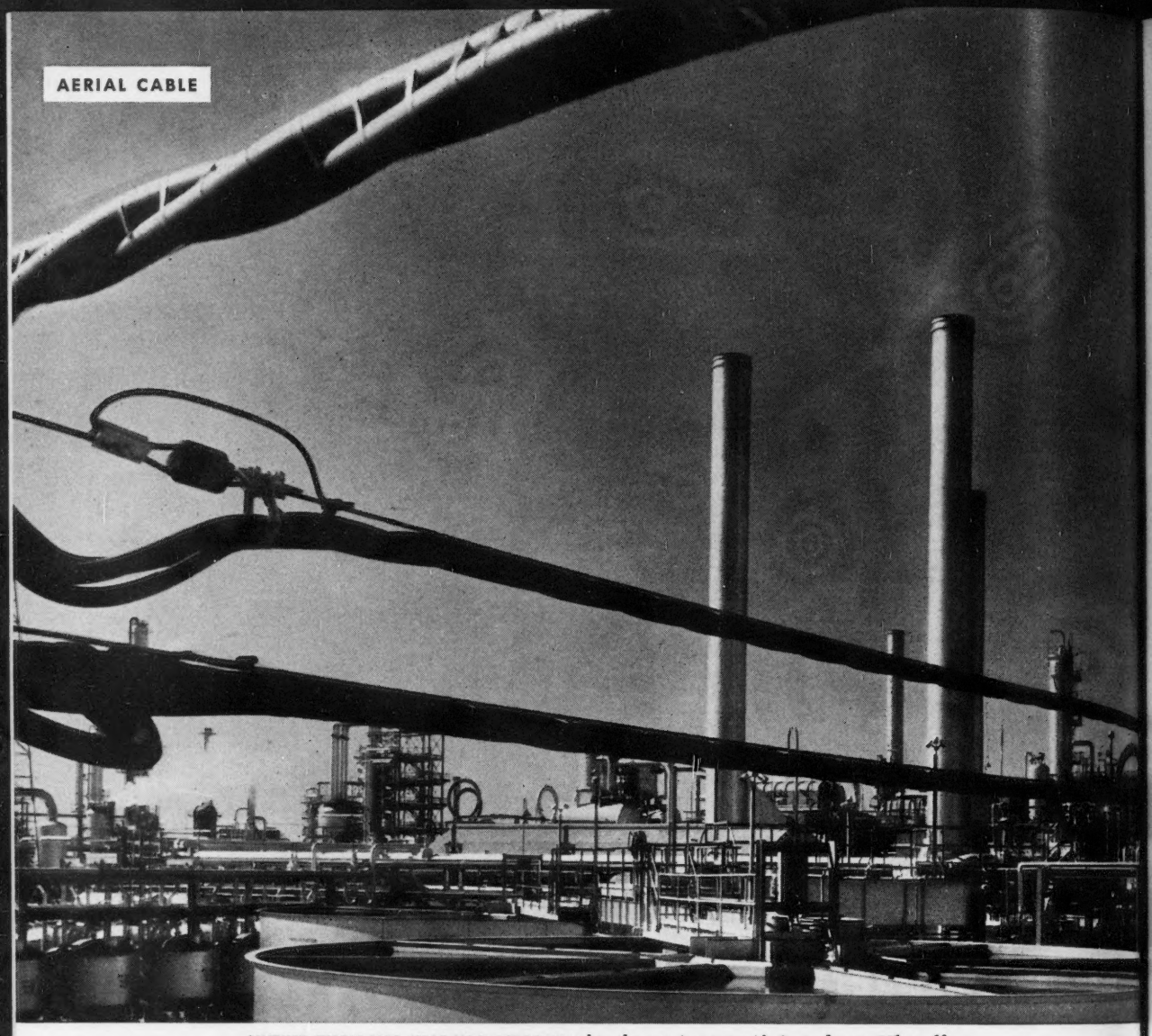
On a big section of this job, Transco specified Carey pipeline protection . . . Carey 8 lb. Glass Reinforced Asbestos Pipeline Felt, Carey Glass and Carey Pipeline Padding . . . the complete Carey line of field-proved wrapping materials.

For **FREE BOOKLET**
of a Corrosion Engineer's own analysis
of pipeline protection problems write Dept. C-3.

THE PHILIP Carey MFG. COMPANY

Lockland, Cincinnati 15, Ohio

ASBESTOS — ASPHALT — MAGNESIA PRODUCTS



NEITHER STORM NOR HEAT NOR CORROSION knocks out ANACONDA's 3-conductor 15kv self-supporting Aerial Cable—shown here at Shell Oil's modern new refinery at Norco, La.

GO UP TO BRING COSTS DOWN

—with AnacondA Aerial Cable

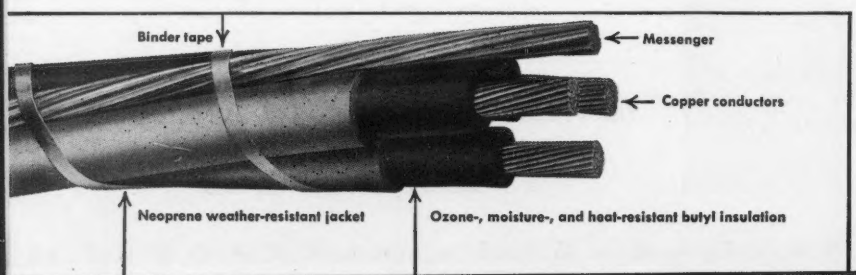
When new power is needed or when old circuits must be replaced quickly and at low cost—more and more plants are turning to ANACONDA Aerial Cable.

In plants where the maze of pipes and other underground structures often make installation of ducts or buried cable costly or difficult. This cable solves the problem.

It's fast, easy to install—particularly in crowded areas. No special ducts or crossarms or insulators are needed. Even in open areas, this rugged, neoprene-jacketed cable costs much less than buried systems.

You can see that it is neat. It is equally safe . . . and reliable!

Today's finest aerial cable! Type AB butyl insulation gives ANACONDA Aerial Cable the finest performance record. For the full story, call the Man from Anaconda today. Or write: Anaconda Wire & Cable Company, 25 Broadway, New York 4, New York.



Ask the Man from

ANACONDA®

about your

High-voltage Aerial Cable

Protect Plant and Equipment with

TYGON "ATD" *Hot Spray* PAINT

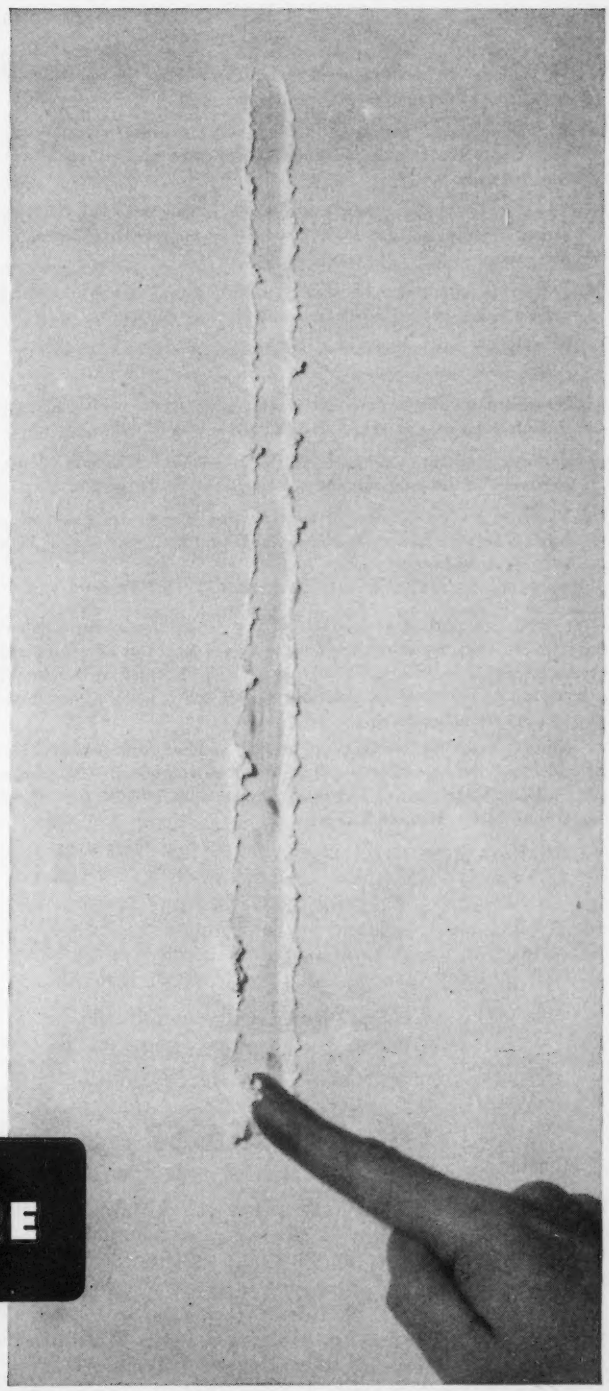
and save three ways:

1. **Lower Applied Cost**
2. **Less Down Time**
3. **Longer Lasting Protection**

It takes thickness in a paint film to give effective, long lasting protection against chemical attack. Corrosion engineers call it the "magic five mils." But to obtain a 5 mil film with conventional cold spray paints means four to five coats, with eight to ten hours drying time between.

But Tygon "ATD" Hot Spray builds the magic five mils in just two slow passes of the spray gun. Labor costs are cut 20%-30%. Down time is held to a minimum. And you get all of the protection against corrosive attack for which Tygon plastic is famous.

Write for the
TYGON COATING MANUAL
This "just-off-the-press" manual is filled with data to make your battle against corrosion easier.



PLASTICS AND SYNTHETICS DIVISION

U. S. STONEWARE

AKRON 9, OHIO

New York Chicago Houston

154E

THE NATIONAL ASSOCIATION OF CORROSION ENGINEERS

is a non-profit, scientific and research association of individuals and companies concerned with corrosion or interested in it, whose objects are:

(a) To promote the prevention of corrosion, thereby curtailing economic waste and conserving natural resources.

(b) To provide forums and media through which experiences with corrosion and its prevention may be reported, discussed and published for the common good.

(c) To encourage special study and research to determine the fundamental causes of corrosion, and to develop new or improved techniques for its prevention.

(d) To correlate study and research on corrosion problems among technical associations to reduce duplication and increase efficiency.

(e) To promote standardization of terminology, techniques, equipment and design in corrosion control.

(f) To contribute to industrial and public safety by promoting the prevention of corrosion as a cause of accidents.

(g) To foster cooperation between individual operators of metallic plant and structures in the joint solution of common corrosion problems.

(h) To invite a wide diversity of memberships, thereby insuring reciprocal benefits between industries and governmental groups as well as between individuals and corporations.

It is an incorporated association without capital stock, chartered under the laws of Texas. Its affairs are governed by a Board of Directors, elected by the general membership. Officers and elected directors are nominated by a nominating committee in accordance with the articles of organization. Election is by the membership.

Inquiries regarding membership, and all general correspondence should be directed to the Executive Secretary at the administrative headquarters of the National Association of Corrosion Engineers at 1061 M & M Building, No. 1 Main Street, Houston 2, Texas.

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Corrosion

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Topic of the Month

Chlorosulfonated Polyethylene (Hypalon) as a Construction Material for Chemical Equipment

By R. McFARLAND, JR.*

CHLOROSULFONATED POLYETHYLENE (Hypalon[1]) is a new elastomeric polymer which has recently come upon the market. It is a highly chemically resistant material suitable for use in mechanical rubber goods and for the lining and corrosion-proofing of chemical equipment.

The method of manufacture of this material consists of the chlorination and sulfonation of the polyethylene pre-polymer by controlled reaction of the polyethylene with chlorine and sulfur dioxide. The commercial polymer contains an average of 1.5 percent sulfur and approximately 30 percent chlorine by weight of the finished polymer. In the manufacture of the chlorosulfonated material a narrow range of molecular weight polyethylene is used in order to give the proper properties of vulcanization, chemical properties and physical properties to the finished, compounded stock.

The introduction of chlorine into the polyethylene polymer results in a reduction in the crystallinity and stiffness of the polyethylene to the point where the product is exceptionally tough but workable. The new product has oil and chemical resistance greatly in excess of the chemical resistance inherent in unmodified polyethylene.

The sulfur dioxide reaction introduces sulfonyl groups which can be used to vulcanize the polymer with a metallic oxide-organic acid system and an accelerator to give a tough high strength elastomeric vulcanizate. Hypalon stocks have inherent good tensile characteristics without filler additions. Use can be made, however, of conventional fillers, carbon black, etc. in compounding.

The material has excellent heat resistance. The best stock in this respect is cured with magnesium oxide and lead oxide as the metallic oxide components of the formulation. The material appears to be serviceable for short periods of exposure to temperatures of 350 F; it is serviceable for several months at 250 F and for extended service life at 200 to 220 F.

Considerable test work has been done on these formulations when processed into valve diaphragms, and successful field tests have been made of diaphragms at the above temperatures in steam service. While it is true that some tack and adhesive properties can be built into the polymer, it is quite difficult to successfully fabricate a complex molded article, with inserts, from this type of stock.

The material has exceptional chemical resistance. In diaphragm form it has been found that the material is useful in valve service where the combined properties of acid resistance, solvent resistance and abrasion are required. Where heat and chemical resistance are required, the material is outstanding among elastomers for this type of service. The oxidation resistance, weathering, ozone resistance, etc., is also exceptional and superior to that of other elastomeric materials.

The physical properties of the material are in many respects excellent. This is particularly true when its corresponding chemical resistance is taken into consideration. The ranges of physical properties listed below are taken from the author's data and from published sources:

Time of cure: 30 minutes at 325 F
Tensile strength: 2300 to 2600 psi
Elongation percent: 300 to 375
Modulus at 100 percent: 800
Shore durometer—type A: 65 to 70
Compression set (method A): 30 percent

It is very important that the stock be properly compounded in connection with compression set, and with reference to the type and method of curing the Hypalon. In order to obtain the lowest values a tight cure is necessary. If the stock is not properly compounded, the compression set might be too high to permit adequate and proper function as a mechani-

* Hills-McCanna Co., Chicago, Illinois.

[1] Trademark E. I. Du Pont de Nemours and Co.

cal part for the service intended. But even in heat resisting stocks the compression set can be accommodated with proper design if stocks have been properly compounded. This will be true even if the compression set is more than that from typical compounds of rubber, neoprene or other elastomeric materials.

The low temperature and abrasion resisting properties and flex life of Hypalon are all excellent. Hypalon loaded stocks have brittle points below minus 40 F, and unloaded stocks have brittle points below minus 80 F. The abrasion resistance of Hypalon is also very good, even in the presence of strongly acid and oxidizing materials.

The chemical resistance of Hypalon is such that it should find considerable application for chemical equipment in tank linings, protective skirts, hose, packing, valve diaphragms and similar items used in contact with corrosive materials. The material is particularly resistant to strong oxidizing materials such as chromic acid, nitric acid, chlorine solutions, chlorine dioxide, sodium hypochlorite. In addition to this it has excellent resistance to hydrochloric, sulfuric, phosphoric, acetic and other acids and acid salts. Its solvent resistance is such that it cannot be recommended for handling hydrocarbon and chlorinated solvents. It should be pointed out, however, that it shows merit where such solvents would be intermixed with acid reagents. This fact is of some importance. The Hypalon material is more serviceable than other elastomers for handling mixtures of acid and solvents in cases where the mechanical design of the part will allow some swelling. (This swelling will result from contact with the solvent portion of the mixture.) There is little published literature to date on the comparative chemical resistance of Hypalon. One report on this subject which is recommended by the author is Bulletin No. BL-261, of the E. I. Du Pont de Nemours and Company, Wilmington 98, Delaware.

Some work has been done on the application of Hypalon linings to tanks, fittings and valves. The main problem is one of shrinkage and proper adhesion of the Hypalon stock to the metal surface. It is reported that the shrinkage problem can be minimized by the incorporation of low molecular weight polyethylene in the compounding and calendaring of the Hypalon stock. The incorporation of this material also influences the problem of adhesion, but considerable progress has been made through the proper compounding and selection of cements to fasten the Hypalon stock to the metal surface. Much of this work is still in the experimental stage. Sufficient application background has yet to be developed through case histories to determine the final limitations on the application and use of various Hypalon stocks for tank lining service.

It is possible to prepare solution coatings of chlorosulfonated polyethylene (Hypalon) for application to rubber or non-metallic surfaces, to fabric and to metal surfaces for special maintenance coatings. In the latter case, adhesion is best secured by the incorporation of modified phenolics in the compound; brittleness of the film can be avoided if only small quantities of the phenolic resin are used. To obtain adhesion, a primer such as the one based on chlorinated rubber can be used. Some work has been done on the use of these solution coatings for immersion in corrosive solutions, and test work indicates that these coatings have possibilities when immersed in chromic acid, sulfuric acid, hydrogen peroxide, brine and similar applications.

Hypalon sheet is particularly adaptable for protecting equipment from splashing or contact with oxidizing corrosive reagents. It is useful also in plating applications for both chromium and nickel in automatic plating equipment to protect equipment from carry over, foaming and splashing when in contact with the corrosive chromium and nickel solutions. It is reported also that industrial rolls have been satisfactorily covered with Hypalon. These rolls are used for rolling and wiping surfaces contaminated with corrosive, oxidizing reagents such as in pickling and plating baths.

Hypalon "20" has recently come upon the market. This product is an improved material having better tack properties and less nerve in order to assist processing. It is reported that Hypalon "20" is a considerable improvement over the original Hypalon polymers. Also, Hypalon "20" can be blended with natural rubber or GRS where it is desired to improve the chemical and age resistance of these materials. On the other hand, while rubber is of some aid in the Hypalon stock for processing and build up operation, the rubber would detract from the chemical resistance of Hypalon "20," where chemical resistance and heat resistance are of primary consideration.

The Selection of Materials for Some Petroleum Refinery Applications*

By J. F. MASON, JR.

Introduction

PETROLEUM REFINING practices of today call for the utmost in performance of metallic materials used in the industry's operating equipment. Chemical stability in all types of corrosive environments, and superior physical properties under adverse conditions of temperature and pressure are more essential than ever to the maintenance of the industry under currently existing competitive conditions.

From the standpoint of tonnage used, simple carbon steels still occupy first place. But refinery engineering is relying more and more heavily as time goes on upon alloys—both ferrous and non-ferrous. It is no exaggeration to say that it would be practically impossible to refine economically many of the corrosive crudes now being utilized were it not for contemporary metallurgical developments which have provided the necessary materials of construction.

During the past 30 years, the author's company has endeavored to keep abreast of developments in the petroleum industry. This has been accomplished primarily through the activities of the Corrosion Engineering Section which has conducted a great many plant tests in refining and related processing equipment. As a result, a large fund of quantitative information has been accumulated on the behavior of different materials under various corrosive conditions. It is the purpose of this paper to present some of these data in order that they may serve as a useful guide in the selection of suitable metals and alloys for specific services.

In the company's field investigations, use was made of the spool-type specimen holder. This permitted the simultaneous testing of a large number of metallic materials in operating equipment under the actual conditions of service, thus giving direct comparisons of the relative performance of the various materials studied. The testing device is illustrated in Figure 1.

This method of test was substantially in accord with ASTM Recommended Practice for Conducting Plant Corrosion Tests, A 224-41.[1] The assembly consisted in part of previously cleaned and weighed specimens of the several metals and alloys to be tested. These samples were mounted on the spool-type holder with non-metallic parts of bakelite or porcelain to separate and insulate the specimens from each other and from the metallic parts of the holder. Two specimens of each material were included on each spool. The completed test assemblies were fastened firmly in place in the desired test locations in operating plant equipment and allowed to remain for sufficient

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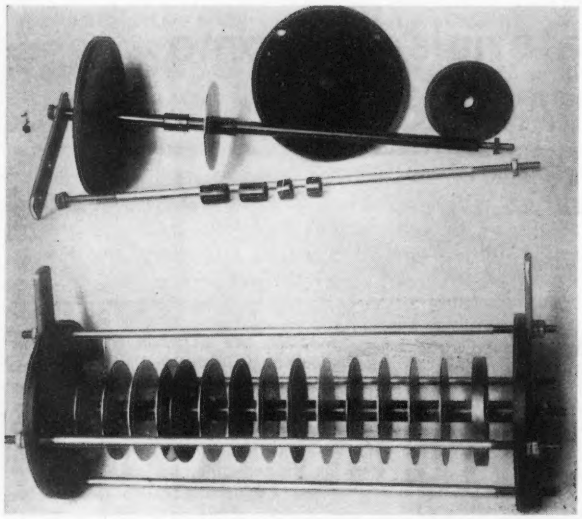

Figure 1—Testing device used in experiments.

lengths of time to give reliable indications of corrosion behavior. Each of the test specimens used had an exposed area of 0.5 sq dm.

Upon completion of tests, the test spools were removed and dismantled. The specimens were examined, cleaned of all scale and corrosion products, and reweighed. From the weight losses, areas of specimens and duration of exposure, the corrosion rates were calculated in terms of mgs per sq dm per day. These rates were converted to inch penetration per year (ipy) as shown in the accompanying tables. This system is based upon the assumption of uniform corrosion in practice from one side of the metal only. The rate shown in the tables for each material is the average of the two specimens included in each test. In addition, each specimen was examined for cracking, pitting, and other forms of local attack. Where pitting or local attack occurred, depth of the five or ten deepest pits was measured microscopically or with a depth gauge. In the accompanying tables maximum depth of pitting is reported where it occurred.

Approximate compositions of the metals and alloys included in one or more of these tests are shown in Table 1.

Atmospheric Crude Distillation

Corrosion in atmospheric crude distillation arises chiefly from two sources: (1) from hydrochloric acid, either formed by hydrolysis of chloride salts (especially calcium and magnesium chloride) entrained in the crudes, or added by the acidizing of wells, and (2) from hydrogen sulfide and other sulfur compounds present in the crudes. Corrosion from both of these sources appears to have been increasing in recent years as a result of the use of crudes with higher salt and sulfur contents. In a case cited by Hamlin and Turner,[2] where the entrained brine in the crude contained 2.2 percent magnesium chloride and 6.5 percent sodium chloride, an acidity equal to 8.23 grains of hydrochloric acid per gallon of water was present after passage through the dephlegmators. Where petroleum contained 1 percent brine, hydrochloric acid was formed in the ratio of 3.39 pounds per 1000 barrels of oil.

Despite the customary practice of settling the salt water from crudes, and in many cases the use of special desalting processes, there still appears to be enough salt water dispersed in such crudes to result in the formation of an acid condition. Corrosion is mitigated in some cases by injection of ammonia into the distillation system to neutralize part of the acid, but experience would indicate that this frequently is not an adequate solution to the problem. Inhibitors of

TABLE 1—Nominal Compositions of Metals and Alloys Used in Corrosion Tests

Material	Nickel, Percent	Copper, Percent	Chromium, Percent	Iron, Percent	Molybdenum, Percent	Silicon, Percent	Manganese, Percent	Carbon, Percent	Zinc, Percent	Other, Percent
Monel	67.0	30.0	.....	1.4	.....	0.1	1.0	0.15	....	.....
"S" Monel	63	30	.....	2	.....	4	.75	.1	....	.....
"K" Monel	66	29	.....	.9	.....	.50	.85	.15	....	Al 2.75
Nickel	99.4	0.1	.....	0.15	.....	0.05	0.2	0.1	....	.....
Inconel	78.5	0.2	14.0	6.5	.....	0.25	0.25	0.08	....	.....
Type 302 S.S.	8–10	.....	17–19	Bal.	.....	0.75 max.	2.0 max.	0.20 max.	....	.....
Type 304 S.S.	8–10	.....	18–20	Bal.	.....	0.75 max.	2.0 max.	0.08 max.	....	.....
Type 316 S.S.	10 min.	.....	16 min.	Bal.	2–3	0.75 max.	2.0 max.	0.08 max.	....	.....
Type 430 S.S.	.....	.....	14–18	Bal.	.....	1.0 max.	1.0 max.	0.12 max.	....	.....
Type 410 S.S.	.....	.....	10–14	Bal.	.....	0.75 max.	0.60 max.	0.15 max.	....	.....
Type 502 S.S.	.....	.....	4–6	Bal.	0.45–0.65	0.50 max.	0.5	0.15 max.	....	.....
70–30 Copper-Nickel	30.0	70.0	.....	.....	.....	.....	.....	.....	....	.....
Admiralty Brass	.....	71.0	.....	.....	.....	.....	.....	.....	28.0	Sn 1.0
Copper	.....	99.9	.....	.....	.....	.....	.....	.....	....	.....
Silicon Bronze	.....	96.0	.....	.....	.....	3.0	1.0	.....	....	.....
Red Brass	.....	85.0	.....	.....	.....	.....	.....	.....	15.0	.....
Yellow Brass	.....	65.0	.....	.....	.....	.....	.....	.....	35.0	.....
Chemical Lead	.....	.....	.....	.....	.....	.....	.....	.....	....	Pb 99.9
Hastelloy A	53.0	.....	.....	22.0	22.0	1.0	2.0	.....	....	.....
Hastelloy B	60.0	.....	.....	6.0	32.0	1.0	1.0	.....	....	.....
Hastelloy C	51.0	.....	17.0	6.0	19.0	1.0	1.0	.....	....	W 5.0
Hastelloy D	85	3	.....	.....	.....	10	1	.....	....	Al 1
Illium G	60.0	4.0	21.0	6.0	6.0	1.0	1.0	.....	....	W 1.0
Aluminum 2S	.....	.....	.....	.....	.....	.....	.....	.....	....	Al 99.0 min.
Pioneer Metal	35	.....	25	Bal.	5	1	.....	.....	....	.....
Aloyco 20	29	3.5	20	Bal.	1.75	1	.....	.07	....	.....
Durimet 20	29	3.5	20	Bal.	1.75	1	.....	.07	....	.....
Durimet L	22.5	19.25	.....	Bal.	.....	3.25	1.10	.25	....	.....
Worthite	24	1.75	20	Bal.	3	3.5	0.6	0.07	....	.....
Ni-Resist	13.5–17.5	5.5–7.5	1.75–2.50	Bal.	.....	1.0–2.5	1.0–1.5	3.0 max.	....	.....
Mild Steel	.....	.....	.....	Bal.	.....	.....	0.3–0.5	0.20 max.	....	.....
Cast Iron	.....	.....	.....	Bal.	.....	1.5–2.5	0.5–1.0	3.0–3.5	....	.....
Corrosiron	.....	.....	.....	Bal.	.....	14.5	.35	.8	....	.....

different types also are being employed with varying results.

It is probable that with salty charging stocks, maximum hydrolysis of magnesium and calcium chlorides occurs in the hottest region at the bottom of distillation towers. Maximum acid corrosion occurs, however, in the top portion of such towers, in reflux and distillate condensers, coolers, and accumulators and in reflux and run-down lines, where temperatures are low enough for an aqueous phase to condense. Maximum corrosion by sulfur compounds will, on the other hand, occur in the higher temperature ranges in the bottom portions of distillation towers and in crude heaters. As the alloys most resistant to acid corrosion frequently are not resistant to high temperature sulfur attack, it is a common practice to line the top and bottom portions of distillation towers with different materials to obtain the most favorable performance.

Table 2 gives the results of corrosion tests on or above the top plate of atmospheric distillation towers handling crudes of different corrosive characteristics. Unfortunately it was not possible in all cases to obtain as complete information as would be desired concerning the source and previous treatment of the charging stocks. It is apparent, however, from the corrosion rates that the crudes contained different amounts of salts to account for the great variations in the degree of attack on a number of the materials tested. It is well known that West Texas crude is highly corrosive toward some materials and this fact is well demonstrated by the results of Test 2. The presence of hydrochloric acid as a corrosive agent is characterized principally by the pitting or general attack that occurs on the stainless steels as well as by the more severe corrosion of mild steel.

Uses for Monel

It will be noted that Monel demonstrates a high level of resistance to both general corrosion and pitting attack. Because of this property it has been used to a considerable extent as a lining or as a Monel-clad steel shell for upper tower sections, reflux and distillate accumulators and condenser shells, and in some cases for reflux and run-down lines. It also is used for fabricated bubble caps, plates and fittings in upper tower sections.

In further connection with the handling of straight-run gasoline and reflux from crude topping, the corrosion test results in Table 3 are presented. These data again indicate that where acidity due to hydrochloric acid prevails the corrosion rate of mild steel is high and that the chromium-containing stainless steels as well as Inconel are subject to localized attack in the form of pitting. On the other hand where the charging stock is sweet crude (as in the case of Test 3) and the condensate contains little or no hydrochloric acid, corrosion of all materials is practically negligible.

The same trend will be noted in Table 4 which gives the results of corrosion tests in reflux water separators where the water layer is free of hydrogen chloride and where it contains some hydrogen chloride as well as hydrogen sulfide. Under these conditions, it is evident that the nickel-base and copper-base materials such as 70-30 cupro-nickel and Admiralty Metal exhibit satisfactory resistance to corrosion even under the more adverse conditions.

Gasoline Condenser Tubes

For the tubes of gasoline condensers and coolers it is customary to use either Admiralty Metal, 70-30 cupro-nickel or Monel depending upon the degree of acidity of the condensate and condition of the cooling water. Typical practice appears to have been to start out using Admiralty and then change to 70-30 cupro-nickel or Monel if the original installation did not prove to be satisfactory.

Note should be taken of the fact that the Ni-Resist

TABLE 2—Plant Corrosion Tests in Top of Crude Fractionating Towers

MATERIAL	Corrosion Rate, Inch Penetration per Year	
	Test 1[1]	Test 2[2]
Monel	0.0005	0.0031
Nickel	0.0002[3]	0.0057[6]
Inconel	0.0002	0.017[7]
Type 302 SS	0.0001[4]	*
Type 304 SS	.....	*
Type 316 SS	.....	0.053[8]
Type 410 SS	0.0003[5]	.....
Type 502 SS	0.0005	.....
Hastelloy B	0.0001	.....
Aluminum 2S	0.0003	.....
Admiralty Metal	0.0007	.....
Copper	*	.....
Silicon Bronze	*	.....
Red Brass	*	.....
Chemical Lead	0.0007	.....
Mild Steel	0.0031	*
Ni-Resist	0.0004	0.051
Cast Iron	0.0007	0.181[9]

[1] Test 1—In straight run gasoline vapor in top of tower. Sulfur content 0.99 percent. Average temperature 220 F. Duration of test 410 days. East Texas crude.
[2] Test 2—In straight run gasoline vapor in top of tower. Average temperature 250 F. Duration of test 60 days. West Texas crude.
[3] Local attack in the form of pitting to a maximum depth of 0.010-inch.
[4] Local attack in the form of pitting to a maximum depth of 0.018-inch.
[5] Local attack in the form of pitting to a maximum depth of 0.008-inch.
[6] Local attack in the form of pitting to a maximum depth of 0.013-inch.
[7] Local attack in the form of pitting to a maximum depth of 0.016-inch.
[8] Incipient local attack—not measureable.
[9] Graphitized.
* Specimens completely destroyed during test. Original thickness 0.031-inch.

TABLE 3—Plant Corrosion Tests in Straight-Run Gasoline From Crude Topping Towers

MATERIAL	Corrosion Rate, Inch Penetration per Year		
	Test 1[1]	Test 2[2]	Test 3[3]
Monel	0.0015	0.0004	0.0003
Nickel	0.0008[4]	0.0007	0.0003
Inconel	0.0002[4]	0.0015[7]	0.0001
Type 302 SS	.....	.....	0.0001
Type 304 SS	0.0001[5]	0.0001[8]	0.0001
Type 316 SS	0.0001	.....	0.0001
Type 430 SS	.....	.....	0.0001
Type 502 SS	.....	.....	0.0002
Admiralty Metal	.....	0.0037	0.0003
70-30 Cupro-Nickel	.....	0.0009	0.0004
Red Brass	.....	.....	0.0003
Chemical Lead	.....	.....	0.0008
Mild Steel	0.0078[6]	0.012[9]	0.0009
Ni-Resist	0.0014	0.0063	0.0001
Cast Iron	0.0066	0.011	0.0004

[1] Test 1—Immersed in 62 degree API gasoline distillate in reflux drum. Ammonia added to system to pH 7-8. Average temperature 100 F. Duration of test 180 days.
[2] Test 2—In vapor of untreated straight-run gasoline in vapor line of first condenser. Average temperature 425 F. Duration of test 290 days.
[3] Test 3—In straight-run gasoline vapor and condensate in shell side of condenser on unit handling sweet crudes. Average temperature 350 F. Duration of test 365 days.
[4] Local attack in the form of pitting to a maximum depth of 0.004-inch.
[5] Local attack in the form of pitting to a maximum depth of 0.005-inch.
[6] Local attack in the form of pitting to a maximum depth of 0.011-inch.
[7] Local attack in the form of pitting to a maximum depth of 0.008-inch.
[8] Local attack in the form of pitting to a maximum depth of 0.016-inch.
[9] Specimens perforated during test. Original thickness 0.031-inch.

austenitic cast-iron alloy is considerably more resistant than cast iron under dilute acid conditions. This material is used for reflux and distillate pumps, valves, and fittings frequently with wrought parts and trim of Monel.

Reference was made previously to the fact that different materials are required for the lining of bottom portions of distillation towers than for top portions. The results of a number of corrosion tests in the bottom of such towers are given in Table 5.

Monel and nickel are subject to severe general and intergranular attack by sulfur compounds at temperatures much in excess of 500 F. On the other hand the austenitic stainless steels, including Types 302, 304 and 316, as well as the ferritic stainless steels are highly resistant to the higher temperature sulfur conditions. Consequently they make the most satisfactory materials for linings or clad steel shells of bottom tower sections. In addition, they also are used for such internals as fabricated bubble caps, trays and fittings in bottom sections.

Practical experience has shown that care should be exercised to eliminate excessive working stresses from such fabricated parts by stress-relief anneal where there is a possibility that some acid condensation might occur (stainless steels are subject to stress corrosion cracking under hot acid chloride conditions).

TABLE 4—Plant Corrosion Tests in Water Layer in Reflux Water Separators

MATERIAL	Corrosion Rate, Inch Penetration per Year	
	Test 1[1]	Test 2[2]
Monel	0.0019	0.0004
Nickel	0.0023	0.0002
Inconel	0.0002[3]	0.0001
Type 302 SS	0.0001[4]	0.0001
Type 410 SS	0.0009[5]	0.0002
Type 502 SS	0.0061[6]	0.0033
Hastelloy B	0.0011	0.0002
Aluminum 2S	0.0018[7]	0.0015[8]
Admiralty Metal	0.0018	0.0004
Copper	*	0.013
Silicon Bronze	0.012	0.013
Red Brass	0.0087	0.011
Chemical Lead	*	0.0001[9]
Mild Steel	0.018	0.0074
Ni-Resist	0.0028	0.0008
Cast Iron	0.0051	0.004

[1] Test 1—Immersed in water layer containing some hydrogen chloride and hydrogen sulfide. Average temperature 120 F. Duration of test 414 days.
[2] Test 2—Immersed in water layer containing some hydrogen sulfide. Neutralization number 0.07. Average temperature 110 F. Duration of test 290 days.
[3] Local attack in the form of pitting to a maximum depth of 0.003-inch.
[4] Local attack in the form of pitting to a maximum depth of 0.015-inch.
[5] Local attack in the form of pitting to a maximum depth of 0.010-inch.
[6] Local attack in the form of pitting to a maximum depth of 0.018-inch.
[7] Local attack in the form of pitting to a maximum depth of 0.017-inch.
[8] Perforated by pitting. Original thickness of specimens 0.031-inch.
[9] Local attack in the form of pitting to a maximum depth of 0.005-inch.
* Specimens completely corroded away during test. Original thickness 0.031-inch.

TABLE 5—Plant Corrosion Tests in Bottom of Crude Topping Towers

MATERIAL	Corrosion Rate, Inch Penetration per Year	
	Test 1[1]	Test 2[2]
Monel	0.016	0.17
Nickel	*	.....
Inconel	0.0002	0.0002
Type 302 SS	0.0001	0.0001
Type 304 SS	.....	0.0001
Type 316 SS	.....	0.0001
Type 410 SS	0.0013[3]	0.0014
Type 502 SS	0.0061	.....
Copper	*	.....
Silicon Bronze	*	.....
Red Brass	*	.....
Chemical Lead	*	.....
Mild Steel	0.0074	0.030
Ni-Resist	0.0033	.....
Cast Iron	0.0061	.....

[1] Test 1—Immersed in reduced crude of 28.1 API containing 0.58 percent total sulfur. Average temperature 525 F. Duration of test 290 days.
[2] Test 2—At bottom of crude fractionating tower approximately 5-inches above tray No. 38 near the overflow side. Average temperature 700 F. Duration of test 120 days.
[3] Local attack in the form of pitting to a maximum depth of 0.004-inch.
* Specimens completely corroded away during test. Original thickness 0.031-inch.

Distillation of Products from Thermal Cracking

The corrosive effects of sulfur compounds are particularly pronounced at the high temperatures encountered in the vapor separators and frequently in the primary fractionation towers immediately following the cracking stills in thermal cracking units. The austenitic stainless steels, as would be expected, show maximum resistance to corrosion. The beneficial effects of smaller chromium additions to steel, as in the 4-6 percent chromium steels, are so pronounced that these materials are usually adequate for towers

TABLE 6—Plant Corrosion Tests in Vapor Separator Thermal Cracking of Gas Oil

MATERIAL	Corrosion Rate, Inch Penetration per Year	
	Test 1[1]	Test 2[2]
Monel	*	*
Nickel	*	*
Inconel	0.0012	0.0012
Type 302 SS	0.0006	0.0001
Type 316 SS	0.0005	0.0001
Type 410 SS	0.0022	0.0003
Type 502 SS	0.0023	0.0028
Aluminum 2S	*	0.0001
Silicon Bronze	0.100[3]	0.080
Mild Steel	0.048	***
Ni-Resist	**	0.018
Cast Iron	0.033	0.066

[1] Test 1—Immersed in residuum from cracked gas oil and vapor in bottom of separator tower. Total sulfur content 0.60 to 0.70 percent. Average temperature 780 F. Duration of test 112 days.
[2] Test 2—Immersed in vapor from gas oil residuum in top of separator tower. Sulfur content of oil condensed from these vapors was about 0.22 percent. Average temperature 753 F. Duration of test 112 days.
[3] Specimens perforated during test. Original thickness 0.031-inch.
* Specimens completely destroyed during test. Original thickness 0.031-inch.
** Specimens completely destroyed during test. Original thickness 0.187-inch.
*** Specimens completely destroyed during test. Original thickness 0.062-inch.

TABLE 7—Plant Corrosion Tests in Fractionation of Pressure Distillate From Thermal Cracking of Gas Oil

MATERIAL	Corrosion Rate, Inch Penetration per Year	
	Test 1[1]	Test 2[2]
Monel	*	*
Nickel	*	*
Inconel	0.0006	0.0005
Type 302 SS	0.0001	0.0001
Type 410 SS	0.0009	0.0004
Type 502 SS	0.0026	0.0024
Aluminum 2S	0.0002	0.0007
Silicon Bronze	*	0.038[3]
Mild Steel	0.038	0.085[4]
Ni-Resist	0.019	0.039
Cast Iron	0.067	0.038

[1] Test 1—Immersed in liquid at bottom of pressure distillate bubble tower handling gas oil with sulfur content of 0.25 percent. Average temperature 675 F. Duration of test 235 days.
[2] Test 2—Immersed in vapor above inlet of pressure distillate bubble tower handling gas oil with sulfur content of 0.25 percent. Average temperature 700 F. Duration of test 112 days.
[3] Specimens perforated during test. Original thickness 0.031-inch.
[4] Specimens perforated during test. Original thickness 0.062-inch.
* Specimens completely destroyed during test. Original thickness 0.031-inch

and associated equipment where elevated temperatures are maintained.

Tables 6 and 7 show the results of corrosion tests in vapor separating towers and in pressure distillate fractionating towers handling the products from thermal cracking of gas oils. Corrosion in both of these unit processes is rather negligible on the chromium-containing materials. The behavior of the more economical straight chromium stainless steels would dictate their use in preference to the austenitic varieties of the stainless steels.

Table 8 gives the results of corrosion tests in the fractionation and stabilization of untreated cracked gasoline derived from thermal cracking. These tests were all made at one refinery and represent performance in the same or adjacent equipment. Corrosion rates are in line with those obtained in the uncracked gasoline from crude distillation as given in Table 4 and probably the same choice of construction materials would be indicated.

Table 9 gives the results of tests in the butts at the bottom of a re-run tower handling stabilized cracked gasoline. This tower previously had been acid and caustic treated. There is a possibility of severe caustic embrittlement of mild steel at the temperature existing at the bottom of such a tower. Such a condition can be avoided by lining the lower portion of the tower with Monel or by the use of Monel or nickel-clad steel.

Caustic Treatment of Petroleum Products

In the processes for removal of sulfur compounds from petroleum products using caustic soda solutions, the corrosive conditions are usually moderate enough so that steel can be used for towers, tanks and other large equipment. However, in the regeneration of the caustic solutions, temperatures and concentrations are high enough that steel may be severely attacked. For that reason it is a common practice to use alloy materials for regenerator reboilers and tubes, for lining the bottom sections of regenerator towers and for pumps, piping and preheaters handling the hot solutions.

The results of plant corrosion tests in the reboilers of caustic regenerator units are shown in Table 10. The data indicate that Monel and Inconel are highly resistant to corrosion. Practical experience has demonstrated the suitability of these materials for hot and moderately high concentrations of caustic soda solutions where steel is subject to excessive corrosion or embrittlement. The austenitic stainless steels exhibit usefully low rates of attack but invariably in this service they have a tendency to suffer stress corrosion cracking.

In the case of steam heating coils for the regeneration of caustic where the wall temperature may be in excess of 500 F, the use of Inconel is indicated. This is because Monel is susceptible to sulfur embrittlement at elevated temperatures in the presence of mercaptans or other sulfur compounds.

Acid Treatment of Distillates

Acid treatment of lubricating oils and other distillates usually is done with successive additions of sul-

TABLE 8—Plant Corrosion Tests[1] in Fractionation of Cracked Gasoline

MATERIAL	Corrosion Rate, Inch Penetration per Year		
	Test 1[2]	Test 2[3]	Test 3[4]
Monel	0.004	0.003	0.0004
Nickel	0.004	0.003	0.0007[9]
Inconel	0.005	0.001	0.0001[10]
Type 302 SS	.....	0.001[5]	.....
Type 304 SS	.....	0.001[6]	.....
Type 316 SS	.....	0.001[7]	.....
Aluminum 2S	.....	0.004[8]	0.0001[11]
70–30 Cupro–Nickel	.....	.....	0.010
Admiralty Metal	0.008	.....	0.001
Mild Steel	0.021	.....	0.002
Ni-Resist	0.002	0.001	0.002
Cast Iron	0.006	0.003	0.003

[1] Duration of tests was 318 days.
[2] Test 1—In vapor in bottom of crude stabilizer. Average temperature 375 F.
[3] Test 2—In liquid in bottom of crude stabilizer. Average temperature 325 F.
[4] Test 3—In reflux accumulator, 5 feet above bottom. Average temperature 110 F.
[5] Local attack in the form of pitting to a maximum depth of 0.015-inch.
[6] Local attack in the form of pitting to a maximum depth of 0.020-inch.
[7] Local attack in the form of pitting to a maximum depth of 0.025-inch.
[8] Specimens perforated during test. Original thickness 0.031-inch.
[9] Local attack in the form of pitting to a maximum depth of 0.007-inch.
[10] Local attack in the form of pitting to a maximum depth of 0.003-inch.
[11] Deep undercutting pits.

TABLE 9—Plant Corrosion Test in Bottom of Stabilized Gasoline Re-Run Tower[1]

MATERIAL	Corrosion Rate, Inch Penetration per Year
Monel	0.0012
Nickel	0.0011
Inconel	0.0007
Type 302 SS	0.0024
Type 410 SS	0.0020
Type 502 SS	0.0015
Chemical Lead	0.0010
Mild Steel	0.0020[2]
Ni-Resist	0.0057
Cast Iron	0.0020

[1] Test made in bottom of tower in butts from stabilized cracked gasoline that had been acid treated and caustic washed. Gravity 25.4 API (basic). Sulfur content 0.422 percent. Average temperature 300 F. Duration of test 350 days.
[2] Local attack in the form of pitting to a maximum depth of 0.008 inch.

TABLE 10—Plant Corrosion Tests in Caustic Regeneration Units

MATERIAL	Corrosion Rate, Inch Penetration per Year			
	Test 1[1]	Test 2[2]	Test 3[3]	Test 4[4]
Monel	0.001	0.0016	0.003	0.002
Nickel	0.024	0.0016	0.022	0.016
Inconel	0.0001	0.0003	0.001	0.002
Type 302 SS	.....	.....	*	0.021
Type 304 SS	.....	.....	*	0.022
Type 316 SS	.....	0.003	.....	.....
Type 502 SS	.....	.....	*	0.017
70-30 Cupro-Nickel	0.025[5]	.....	0.015	0.012
Mild Steel	0.020[6]	0.033[7]	**	0.012
Ni-Resist	0.023	0.013	0.046	0.019
Cast Iron	0.017	.....	0.040	0.014

[1] Test 1—In reboiler of caustic soda regenerator unit. Solution entering contained 1-2 percent sodium hydroxide, 3 percent sodium phenolate and 0.07 mg per 100 cc of solution as sodium mercaptides. Test specimens were located directly above Monel heating tubes. Temperature 255 F. Duration of test 131 days.
[2] Test 2—In vapor section of caustic soda regeneration unit. Solution entering contained 13.2 percent sodium hydroxide, 0.37 percent sulfide sulfur and 0.80 percent mercaptide sulfur. The average temperature was 300 F. The duration of test was 55 days.
[3] Test 3—In reboiler of caustic potash regenerator unit. Solution entering contained 25.5 percent potassium hydroxide, 37.8 percent potassium isobutyrate, 5.5 percent potassium sulfide, 1.9 percent potassium mercaptides and 2.1 percent potassium carbonate. Test specimens were located in boiling liquor at upstream side of overflow weir. Average temperature 286 F. Duration of test 140 days.
[4] Test 4—Same as "3" above except test specimens were exposed in vapor at downstream side of overflow weir. Average temperature 286 F. Duration of test 140 days.
[5] Local attack in the form of pitting to a maximum depth of 0.002 inch.
[6] Local attack in the form of pitting to a maximum depth of 0.012 inch.
[7] Local attack in the form of pitting to a maximum depth of 0.018 inch.
* Specimens completely destroyed during test. Original thickness 0.031 inch.
** Specimens completely destroyed during test. Original thickness 0.062 inch.

furic acid of 66 degree Bé or higher strength. The amount of acid used may vary from 5 to 25 or more percent by weight of the charge depending upon the source and viscosity of the distillate. Temperatures usually range from atmospheric to 150 F., but may go as high as 220 F.

Mixing is accomplished by a variety of means including mechanical agitators, circulating pumps, contacting towers, or by special devices such as mixing nozzles. In some cases air agitation may be used. The acid picks up some water from the oil but usually must be further diluted with water to accomplish good separation of the acid sludge after treatment. Because of this development water solutions of acid concentration down to 5 or 10 percent may be encountered in the separation of systems.

In batch operations it is a frequent practice to do mixing, settling, water washing, and sometimes caustic neutralization all in the same vessel. In continuous systems and in some batch systems, these various steps may be accomplished in separate vessels. In Table 2 are given the results of plant corrosion tests in batch vessels where acid treatment and some water dilution were carried out in the same vessels. These tests were made in five different plants under a variety of conditions of acid concentration, temperature and agitation.

During the mixing of concentrated acid and oil, corrosion usually is not severe at moderate temperatures. This situation is a result both of the dispersion of the acid in the oil and the film forming and inhibiting properties of the oil. This is indicated by Test 1 in Table 2, which was made during agitation of concentrated sulfuric acid with crude oil at atmospheric temperature. In this case mild steel shows satisfactory resistance.

Tests 2, 3 and 4 were made in batch vessels where mixing, dilution and settling were carried out in the same vessel. Test 2 was made in the 6 inch discharge line of the treating tank and Test 3 in the vessel just above the discharge nozzle. Temperature conditions were about the same and corrosion rates are somewhat similar. Under those conditions, treating tanks of Monel or Monel-lined steel are commonly used.

Test 5 was made in a batch vessel in which acid treatment, water washing and caustic treatment were all carried out in the same vessel and agitation was done with air. Air-agitation has increased somewhat the corrosion rate of Monel during the acid treating cycle.

TABLE 11—Plant Corrosion Tests in Sulfuric Acid Treatment of Petroleum Distillates

MATERIAL	Corrosion Rate, Inch per Year				
	Test 1[1]	Test 2[2]	Test 3[3]	Test 4[4]	Test 5[5]
Monel	0.0003	0.006	0.003	0.003	0.018
"K" Monel	.....	.....	0.003	.....	.....
"S" Monel	.....	.....	0.006	.....	.....
Nickel	0.0008	.....	0.013	0.011	0.037
Inconel	.....	0.015	0.014	0.016[6]	0.016
Type 302 SS	.....	.....	0.019[7]	.....	.....
Type 304 SS	.....	.....	0.008[7]	.....	.....
Type 316 SS	.....	0.008	0.006[7]	.....	.....
70-30 Copper-Nickel	0.0002	.....	.....	0.005	.....
Durimet L	0.0009	.....	.....	.....	.....
Worthite	.....	0.003	0.004	.....	0.012
Hastelloy A	.....	.....	.....	.....	0.003
Hastelloy B	.....	0.009	.....	.....	.....
Hastelloy C	.....	0.002	.....	.....	.....
Hastelloy D	.....	.....	0.009	.....	.....
Illium G	.....	0.003	.....	.....	.....
Chemical Lead	.....	.....	.....	0.025	0.038
Ni-Resist (Type 1)	0.003	0.008	0.021	.....	0.036
Cast Iron	0.044	*	0.16	.....	0.056
Mild Steel	0.007	.....	0.090	.....	0.021

[1] Test 1—Immersed in treating tank during agitation of acid with crude oil. Mechanical agitation. Temperature, atmospheric. Duration of test 92 days.
[2] Test 2—Immersed in acid sludge containing 25 percent H_2SO_4 in 6 inch discharge line from acid treater. Average temperature 60 C (140 F). Duration of test 55 days. Mechanical agitation.
[3] Test 3—Immersed above draw-off nozzle of lube oil acid-treater. After mixing and dilution of acid, the lube oil mixture contains 2 percent H_2SO_4, 40 percent water, and 58 percent hydrocarbons. Temperature 32-66 C (90-150 F). Duration of test 15 days. Mechanical agitation.
[4] Test 4—Immersed in lube oil acid-treating tank. Acid content of mixture 25 percent H_2SO_4. Temperature up to 104 C (220 F). Duration of test 10 days. Mechanical agitation.
[5] Test 5—Immersed 3 feet above bottom of core in fuel oil treating tank during treatment with 4 pounds per barrel of 66 degrees Bé acid followed by water washing and treatment with 10 degree Bé caustic soda. Agitated with air. Temperature 27-41 C (80-105 F). Duration of test 56 days.
[6] Pitted to maximum depth of 0.010 inch.
[7] Pitted to maximum depth of 0.002 inch.
* Specimens corroded entirely away. Original thickness 3/16 inch.

Pumps and Valves

For pumps and valves handling the acid sludge from the treating units, a number of materials have been used satisfactorily including Monel and the nickel-chromium-molybdenum-iron alloys such as Worthite, Durimet 20, Durimet T, and Aloyco 20. In some cases Monel valves trimmed with Hastelloy C or Illium are used. The selection of materials appears to depend upon general plant experience and principally upon the temperature of the sludge. Where separation of oil from sludge is done in high-speed centrifugals, the bowls of these centrifugals are commonly machined from Monel forgings. Monel filter cloth is used in the filtering of clay-treated acid stocks.

In some cases it is the practice to remove the settled acid sludge from treating or settling tanks into separate vessels and dilute with hot water to accomplish a further acid separation and recovery. If only mild agitation is used in this process, corrosion rates somewhat similar to those in Table 11 can be expected. However, if violent agitation with live steam is used

TABLE 12—Plant Corrosion Tests in Acid Dilution and Separation With Live Steam

MATERIAL	Corrosion Rate, Inch per Year		
	Test 1[1]	Test 2[2]	Test 3[3]
Monel	0.074	0.028	0.056
Nickel	*	0.054	0.054
Inconel	*	0.072	0.068
Type 302 SS	*	0.12	0.077
Type 304 SS	*	.....	0.095
Type 316 SS	*	0.059[4]	0.072
Hastelloy B	0.12	0.031[5]	0.002
Durimet 20	0.16	.....	0.046
Worthite	0.080	0.017	0.027
Pioneer Metal	0.14	.....	0.062
Illium R	0.072	0.031	0.029
Aloyco 20	.....	0.017	.....
Chemical Lead	*	.....	0.020
Mild Steel	**	.....	0.14

[1] Test 1—Immersed 4 feet above bottom of 14 foot separating tank during dilution and separation of sulfuric acid from acid sludge. Acid concentration in acid layer reduced to 35 percent H_2SO_4 and in "tar" layer to 10-15 percent H_2SO_4. Violent agitation with 120 psi live steam. Temperature 66-104 C. (150-220 F). Duration of test 29 days.
[2] Test 2—Same conditions as Test 1, except that test spool was suspended 6 feet above bottom of separating tank for 10 days, then fell to bottom of tank and remained there for balance of test period. Temperature 66-104 C (150-220 F). Total duration of test 19 days.
[3] Test 3—Immersed 3 feet from bottom of sludge oil storage tank in sludge oil recovered from separators of Tests 1 and 2. Contains 10-15 percent H_2SO_4 Violent agitation with 120 psi live steam. Temperature 66-104 C (150-220 F). Duration of test 22 days.
[4] Pitted to maximum depth of 0.016 inch.
[5] Pitted to maximum depth of 0.012 inch.
* Specimens corroded entirely away. Original thickness 0.031 inch.
** Specimens corroded entirely away. Original thickness 0.062 inch.

there is a possibility of encountering high corrosion rates.

The test results reported in Table 12 were obtained in the separating tanks of such a system. These two tests were made in adjacent separating tanks at the same refinery. The acid sludge is pumped to these tanks, diluted with hot water, and violently agitated with 120 pounds per square inch live steam until a "tar" separation occurs. At this point the acid concentration of the acid layer is about 35 percent H_2SO_4, and in the "tar" layer it is about 10-15 percent H_2SO_4. The acid layer is removed and the "tar" layer pumped to a sludge oil storage tank.

In Test 1, the corrosion test spool was suspended about four feet from the bottom of a 14 foot tank during the complete test. In Test 2, the test spool was originally located about six feet above the bottom of a similar tank but after ten days it fell to the bottom and remained there for the balance of the 19 day test period. The tank bottom was brick lined and the spool remained intact so that there was no galvanic corrosion of specimens involved.

It is apparent from the lower corrosion rates in Test 2 that corrosive conditions were considerably less severe near the bottom of the tank than under the highly turbulent conditions existing above the steam inlet. The effect of steam agitation combined with high temperature also is shown by the results of Test 3, obtained at the same plant in the sludge oil storage tank.

Brick-Lined Steel

Under such highly corrosive conditions as those illustrated by Table 12, brick-lined steel possibly would be required for the separating tanks with Hastelloy B and lead perhaps having some application in the storage tank. Where the acid sludge from treating processes is burned under the boilers, both Illium and cast hardened "S" Monel are used for burner tips.

Sulfuric Acid Alkylation

In the sulfuric acid alkylation processes, the hydrocarbons are emulsified with sulfuric acid of 95 to 100 percent concentration and reacted at low temperatures of 30 to 50 F. The nature of the process is such that the acid remains in fairly concentrated form, being diluted mostly with carbonaceous materials to about 88 percent. With these high acid concentrations and low temperatures, mild steel has satisfactory corrosion resistance except where conditions of high velocity or turbulence are encountered as in pumps, valves, and return bends. For these locations, Type 304 or Type 316 stainless steel usually are satisfactory.

TABLE 13—Plant Corrosion Tests in Sulfuric Acid Regeneration Tower of Isobutylene Extraction Plant[1]

MATERIAL	Corrosion Rate, Inch Penetration per Year
Monel	0.080
"S" Monel	0.11
Hastelloy A	0.045
Hastelloy B	0.040
Hastelloy C	0.065
Hastelloy D	0.071
Illium G	0.10
Corrosiron	0.002
Ni-Resist (Type 1)	0.67
Copper	0.16

[1] Test spool located in bottom section of acid regeneration tower in 65-45 percent sulfuric acid. Temperature 38-116 C (100-240 F). Duration of test 14 days.

After initial separation of the alkylate from the spent acid, a portion of the latter usually is removed to other separator tanks where the acid is diluted to separate from it a layer of heavy hydrocarbons or "tar." This dilution may be accomplished with water, or with dilute sulfuric acid recovered from other sulfuric acid processes in the same plant. Because the acid concentration may be reduced to 40-60 percent and temperatures may be as high as 240 F., corrosion in these recovery processes is likely to be severe and of the same order as the rates shown in Table 13.

If the mixture is agitated with steam during the dilution process, corrosion may be extremely severe as indicated by test results given in Table 14. In this case the spent 86 percent alkylation acid was diluted with hot recovered 35 percent acid to 58 percent concentration; the mixture was violently agitated with 125 pounds per square inch live steam. In such a case, the separator tank would need to be brick lined with necessary metallic parts of Duriron, Corrosiron, Hastelloy D, or possibly an alloy composition such as Illium. Piping handling the hot acid probably should be lead-lined or carbon-lined.

Hydrofluoric Acid Alkylation

Fortunately hydrofluoric acid is in substantially anhydrous form and at moderately low temperatures in most of the alkylation process in which it is encountered. For this reason carbon steel can be used for most of the major equipment except that involved in the acid regeneration units. Several years' operating experience in alkylation plants have confirmed the satisfactory performance of steel within the limits specified. Holmberg and Prange[3] report that corrosion rates of about 0.01 inch per year are experienced in the low-temperature parts of HF alkylation equipment and rates of 0.03 to 0.05 inch per year in the sections handling nearly anhydrous acid at 150 F.

The most corrosive conditions in HF alkylation plants normally exist in the acid-regeneration units, including the acid regeneration column and its pre-

TABLE 14—Plant Corrosion Test in Dilution and Separation of Spent Alkylation Acid with Live Steam[1]

MATERIAL	Corrosion Rate, Inch Penetration per Year
Monel	0.13
Nickel	*
Inconel	0.29
Type 302 SS	0.31
Type 304 SS	*
Type 316 SS	*
Hastelloy B	0.11
Durimet 20	0.18
Worthite	0.24
Illium R	0.078
Pioneer Metal	0.18
Chemical Lead	0.083
Mild Steel	0.67

[1] Separator tank is partially filled with 35 percent sulfuric acid recovered from acid treating. Spent 86 percent alkylation acid is added, resulting in mixture of 58 percent sulfuric acid and "tar" from which acid layer settles. Test made in 35 to 58 percent acid layer, 5 feet above outlet of 10 feet deep conical bottom of tank. Total depth of tank 27 feet. Violent agitation with 125 psi live steam. Temperature 66-127 C (150-260 F). Duration of test 16 days.

* Specimens corroded entirely away. Original thickness 0.031 inch.

TABLE 15—Plant Corrosion Tests in Hydrofluoric Acid Alkylation Plants

MATERIAL	Corrosion Rate, Inch Penetration per Year			
	Test 1[1]	Test 2[2]	Test 3[3]	Test 4[4]
Monel	0.0003	0.0005	0.0075	0.022
Nickel	0.0011	0.014	0.011	0.068
Inconel	0.0008	0.025	0.023	>0.13[1]
70-30 Cupro-Nickel	0.0011	0.0053	0.021	.....
Type 302 SS	.....	>0.11[1]	0.036	.....
Type 304 SS	.....	0.063[2]	0.045	.....
Type 316 SS	.....	0.001	0.0015	.....
Aluminum 2S	.....	0.035	>0.12[1]	.....
Copper	0.019	>0.12[1]	>0.12[1]	>0.13[1]
Silicon Bronze	0.012	.....	.....	>0.12[1]
Mild Steel	0.027	0.20[3]	0.036[4]	>0.24[2]

[1] Test 1—Inlet side of preheater channel. Liquid composition: 79 to 92 percent HF, 0.8-2.5 percent water, remainder isobutane and acid-soluble oil. Temperature 120 F, average; 135 F maximum. Duration of test 111 days.
[2] Test 2—Top of regeneration column. Composition: equal parts of 93 percent HF and isobutane vapor. Temperature 215 F. average; 220 F. maximum. Duration of test 49 days.
[3] Test 3—Bottom of regeneration column in acid tar containing 1-10 percent HF-Water in a 1:1 ratio. Average temperature 250 F. Duration of test 49 days.
[4] Test 4—Bottom of dehydrator column beneath bottom plate. Feed contains 89.3 percent HF, and 1.6 percent water. Feed rate 15 barrels/day. Temperature 225 F, average; 250 F maximum. Duration of test 45 days.
[5] Completely corroded away. Original thickness 0.032 inch.
[6] Perforated by pitting. Original thickness 0.032 inch.
[7] Perforated by pitting. Original thickness 0.062 inch.
[8] Pitted to a max. depth of 0.008 inch during test.

TABLE 16—Plant Corrosion Test in a Furfural Extract Separation Tower[1]

MATERIAL	Corrosion Rate, Inch Penetration per Year
Monel	<0.0001
Nickel	<0.0001
Inconel	<0.0001
Type 302 SS	<0.0001
Type 316 SS	<0.0001
Type 410 SS	0.0014[2]
Type 502 SS	0.0001
Chemical Lead	0.0026[3]
Aluminum 2S	0.0002
Mild Steel	0.011[3]
Ni-Resist	<0.0001
Cast Iron	0.0001

[1] Test spool located in the down-pour between the bubble trays in an extract separation tower. Temperature 450-460 F. Duration of test 122 days.
[2] Pitted to a maximum depth of 0.012 inch during test.
[3] Specimens perforated during test. Original thickness 0.062 inch.

heater, and the acid-dehydrating column. As the alkylation process proceeds, the HF gradually becomes contaminated with high molecular-weight organic material and water which remain dissolved in the acid. A portion of the acid is continuously removed from the cycle, heated and distilled from the organic material in the regeneration column. A portion of the overhead acid and water from the column goes to the dehydrating column where substantially anhydrous HF is distilled overhead and the water removed from the bottom as a HF solution of 38 to 45 percent concentration.

In order to determine the performance of metals and alloys in these units under operating conditions, corrosion tests were made in various parts of the regeneration equipment. Table 15 gives the results obtained in the inlet to a preheater, in the top and bottom of a regenerator column and in the bottom of a dehydrator column. The data indicate that Monel is outstanding in its corrosion resistance. Practical experience has demonstrated its suitability for such equipment as acid recovery towers and heaters, bubble caps in distillation equipment as well as valves, bolts, pumps and pipe lines for the most corrosive conditions encountered.

The 70-30 cupro-nickel alloy may be considered next to Monel in general performance. The principal use of this material has been for heat exchanger tubes in applications where the acid concentrations may vary from dilute to anhydrous. The austenitic stainless steels are subject to severe corrosion by the hot acid solutions and their use is generally avoided in HF service.

Furfural Recovery

In some raw lube oil refining systems employing furfural, corrosion of steel regenerating equipment has presented a problem particularly above the vapor line at each tray level. The corrosive condition seems to be associated with the decomposition products of furfural at elevated temperatures. The results of a plant corrosion test in a furfural extract separation tower as shown in Table 16 indicate the severity of attack that can be encountered.

The data also show that chemical lead and Type 410 stainless steel are unsatisfactory under the particular test conditions because of their tendency to suffer severe localized corrosion. All of the other materials investigated showed an absence of this form of corrosion and at the same time showed negligibly low rates of general attack. Some practical experience with a Monel-lined furfural treating tower equipped with Monel internals has indicated that after 15 years service it was still in very satisfactory condition.

The test results presented are typical of many that have been developed over the years in the refining of petroleum using the spool-type specimen holder. Such information has proved to be a highly useful guide to the selection of materials for corrosive applications. It is suggested that the spool-type specimen holder be used where quantitative data are not available on the relative behavior of different metals and alloys under a specific set of corrosive conditions.

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Any discussions of this article not published above will appear in the June, 1956 issue

Preventing Corrosion of Lead Sheathed Power Cables In Concrete Tunnels*

By R. I. PERRY

R. I. PERRY—A senior engineer with Commonwealth Edison Company of Chicago, Ill., he has been employed by that company for the past 29 years. During that time he has been actively engaged in mitigation of corrosion of his company's equipment. He has a BS in electrical engineering, is a registered professional engineer in the state of Illinois and a member of NACE.

Abstract

An appreciable amount of corrosion was found to exist on the lead sheaths of underground power cables where these cables were located in concrete tunnels. The corrosion occurred at several locations in a metropolitan city where the lead sheathed cables were installed in continuous, precast concrete ducts and in ducts of other non-metallic materials encased in concrete and placed in concrete tunnels under waterways. Tests indicated that the corrosion on the lead sheathed cables was caused by calcium hydroxide from incompletely cured concrete.

Typical chemical analyses are shown of water from the continuous ducts. The sheath voltages and water conditions under which these cables operated are given and the methods employed to reduce the concentrations of calcium hydroxide in the continuous ducts are described. The pH values and concentrations of calcium hydroxide are shown for the water in the conduits in two tunnels prior to, and after corrective measures were taken.

The methods now used by this company to cure concrete in tunnels before lead sheathed power cables are installed are described. A brief description is given of the prelubrication of continuous tunnel ducts before pulling in large cables. Corrosion is reduced by the application of pulling grease to the cables at the time of installation.

Introduction

OVER THE past 50 years, most of the underground lead sheathed power cables installed in the United States have been pulled into ducts of concrete or into ducts of other non-metallic materials encased in concrete envelopes. This type of conduit construction for power cables has in most cases proven entirely satisfactory. In some instances, however, the lead sheathed cables have been subjected to corrosion by calcium hydroxide from the concrete. Where corrosion occurred from this cause, it usually resulted from improper design of the conduits or from insufficient curing of the concrete before pulling in the cables.

A large utility company has experienced an appreciable amount of corrosion on the lead sheaths of underground power cables where these cables have been installed in concrete tunnels. The corrosion occurred where the lead sheathed cables were installed in continuous precast concrete ducts and in ducts of other non-metallic materials encased in concrete and placed in concrete tunnels under waterways at several locations in a metropolitan city. Investigation has established that the cable sheath corrosion which occurred in these tunnels was caused by calcium hydroxide from the surrounding concrete. The conditions under which the power cables operated and the methods used to reduce the rate of corrosion on these cable sheaths are described in this paper.

Corrosion of Lead by Calcium Hydroxide

Calcium hydroxide, free hydrated lime-$Ca(OH)_2$, is always present in concrete due to its formation in the hydration of portland cement. This calcium hydroxide is gradually converted into calcium carbonate and thus becomes a part of the concrete structures. Calcium hydroxide in concrete that remains dry does not corrode lead but in the presence of moisture it may, and often does, cause severe corrosion of lead.

Concrete which has been exposed to the air sufficiently long to bring about complete carbonation of the hydroxide at the outer surfaces will in most cases have little effect on lead which may come in contact with these surfaces. Water flowing over well cured concrete will usually absorb very little calcium hydroxide, but water seeping through concrete will do so to some extent and may even become saturated. Water containing a sufficient amount of calcium hydroxide will corrode lead. Therefore, if concrete has cured long enough and is dense enough to prevent the passage of water through it, lead sheathed cables in concrete ducts and in ducts of other non-metallic materials encased in concrete should not be subject to calcium hydroxide corrosion.

Tunnels

On the underground cable plant being considered there are 16 concrete tunnels containing lead sheathed power cables under several waterways. These tunnels have been constructed at different times over the past 52 years. The first ones were built in 1903 and the latest one completed in 1953.

The tunnels are constructed of reinforced concrete and consist of continuous bores having a wall thickness of approximately one foot. Tunnels constructed prior to 1953 each have two vertical shafts which are connected by horizontal drifts. The vertical shafts are circular with inside diameters of 6 or 6½ feet. In some tunnels the drifts are also circular

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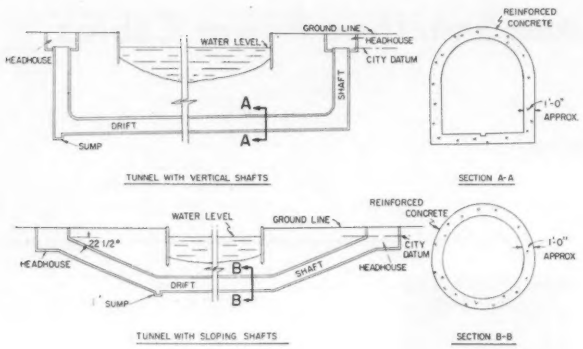

Figure 1—Tunnels for lead sheathed cables.

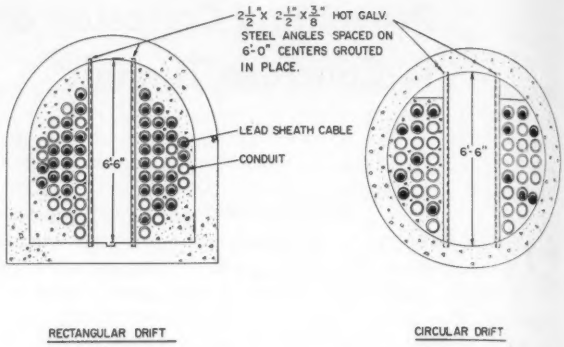

Figure 2—Arrangement of conduits in tunnel drifts.

while in others the drifts are rectangular, having arched ceilings. Drifts are constructed on 3 or 3½ foot radii with the center of the arches 6½ feet above the tunnel floors.

The vertical shafts for tunnels vary in depth from 37 to 73 feet below city datum and the horizontal drifts are from 250 to 575 feet in length. The drifts slope slightly toward one end. Sumps are installed in the bottom of the shafts at the lower ends of the drifts to provide facilities for pumping water from the tunnels.

The headhouses for the tunnel built in 1953 are placed back some distance from the waterway and the shafts are on an angle of 22½ degrees between the headhouses and the horizontal drifts. This type of construction eliminates sharp bends in the conduits at the junctions of the shafts and drifts. Otherwise, the construction of this tunnel is similar to those built at an earlier date. Figure 1 shows the general design of concrete tunnels for the installation of lead sheathed power cables.

Conduits in Concrete Tunnels

Conduits are placed on each side wall of the tunnels, leaving continuous open passageways approximately 26 inches wide. In the older tunnels the conduit banks were made up of individual square tile ducts, encased in concrete sheathings, whereas in the more recent tunnels precast concrete, asbestos cement, and some fibre ducts were used.

Asbestos cement ducts were installed in the tunnel constructed in 1953. The ducts are of different sizes and range from 2½ to 5 inches inside diameter. The number of ducts installed in the sides of each tunnel varies from 15 to 31, depending on the size of ducts and the number required. There is approximately one inch of concrete between the ducts. Duct banks are encased in concrete sheathings which may vary from 3 to 6 inches in thickness.

In the early installations the tile conduits were not continuous; conduits were placed in each shaft and drift. At the junctions of the shafts and drifts there were spaces of several feet where there were no conduits. This made it necessary to use cable-racking facilities similar to those used in manholes at these locations. In addition it was necessary that the cables in the openings be arc-proofed. Under these conditions, in order to install or remove cables, it was first necessary to pump out the water from the tunnels. The task required 8 to 16 hours. The conduits not being continuous also called for the use of complicated pulling arrangements for the installation or removal of cables.

In the four tunnels built since 1922, conduit bends were installed at the junctions of the shafts and drifts during the time of construction. In 1926, a program was initiated to replace the tile conduits in the older tunnels with continuous conduits. In the beginning of this program different materials were used for the bends, including precast concrete, asbestos cement, fiber, steel and brass pipe. Preformed asbestos cement bends were used in the more recent installations. Continuous conduits have now been placed in 15 of the 16 tunnels.

One-half of each of two tunnels on the underground cable plant contains cables belonging to a telephone company. The design of the conduits for these communication cables is somewhat different from that used for power cables. Figure 2 shows the general construction details and arrangement of conduits in concrete tunnels for the installation of lead sheathed power cables under waterways on the underground cable system.

Water Levels and Sheath Voltages

The tunnels normally contained water, with the water levels reaching aproximately city datum (river level). Most of the drifts were located in the blue clay soil although two of the drifts were known to be in limestone rock.

The tunnels all contained multi-conductor lead sheathed cables. Several contained both multi-conductor and single-conductor cables, which are operating at different voltages between 120 and 132,000 volts.

The tunnels were located in a stray current area and the sheaths were subjected to various values of DC potentials. In tunnels near generating stations and in the downtown area, the sheaths operated under DC potentials in the order of 0.1 and 0.2 of a volt negative with respect to earth. In other areas the DC potentials were somewhat higher, and averaged between 0.5 and 1.0 volt negative to earth during the normal street railway load periods. In the early morning hours when the street railway loads

were light, the negative sheath potentials with respect to earth approached zero. At present, the negative DC sheath potentials in most of the tunnels have been reduced materially due to the recent reduction in the use of street cars by the local transportation system.

The sheaths of the high-voltage, single-conductor cables were bonded for the prevention of sheath losses. The sheaths of these cables also were subjected to AC potentials, which were limited by design to a maximum value of 17 volts to ground.

The sheath corrosion which occurred in the several tunnels indicated that the differences in the negative voltage with respect to earth did not appear to have any appreciable effect on the rate of cable sheath corrosion.

Cable Sheath Corrosion

In 1933, cable failures began to occur as the result of corrosion of the lead sheaths in some of the tunnels where the old tile conduits had been broken out and replaced with new continuous conduits. Severe corrosion also was found on the sheaths of some cables which were removed from the continuous conduits because of system changes or failures from causes other than corrosion. In all cases, however, the most severe corrosion was found to have occurred near the bottom of the shafts or in the drifts.

Careful examination of the removed cables indicated that the corrosion might have been caused by chemical action. Longitudinal grooves and irregular areas were corroded in the sheaths, being most severe in the areas where the cables had been scored during installation. Corrosion products were found only in small amounts in the corroded areas. The material found was a soft, dark grey substance consisting either of finely divided lead or of a sub-oxide of lead. Spongy lead and apparently redeposited lead also were found. Occasionally a little red oxide of lead was present on the sheaths adjacent to the severely corroded areas. Figure 3 shows the type of corrosion found on cable sheaths removed from continuous conduits in the concrete tunnels.

Investigation

Voltage readings indicated that the cable sheaths were negative with respect to earth. Chemical analyses of water samples taken from open passageways near the bottom of the shafts showed the chemical composition of these samples to be similar to river water and to have pH values between 7 and 8. Before installation of the continuous conduits, no failures of cables caused by corrosion of the lead sheaths were known to have occurred in these tunnels.

A sample of water taken from near a bend in a vacant, continuous duct in one of the tunnels showed a chemical composition very different from the water in the open passageways. The pH value for this sample of duct water was 11.7 and it contained 350 parts per million of calcium hydroxide and 86 parts per million of sodium hydroxide (a total of 436 parts per million of hydroxides).

Further investigation showed the pH values for water samples from a continuous duct in each of the other tunnels to vary from 10.9 to 12.2 and the amount of hydroxides contained in these water samples to range from 100 to 1008 parts per million. In some tunnels an appreciable amount of sodium hydroxide was present in the continuous ducts. It is

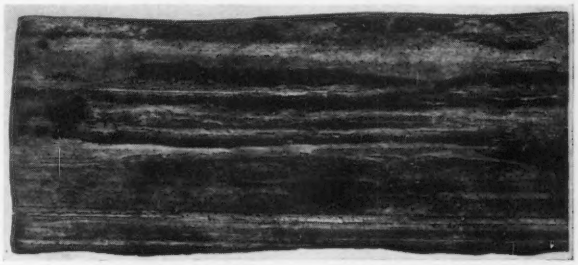

Figure 3—Lead sheath corrosion caused by calcium hydroxide.

TABLE 1—Chemical Analysis of Water From a Continuous 4-Inch Precast Concrete Duct in a Concrete Tunnel

MATERIAL	Parts per Million	Percent of Total Solids
Silica, SiO_2	4	0.5
Iron and aluminum oxides, Fe_2O_3—Al_2O_3	2	0.2
Sodium chloride, NaCl	74	8.5
Sodium sulphate, $NaSO_4$	49	5.6
Sodium nitrate, $NaNO_3$	12	1.4
Sodium hydroxide, NaOH	86	9.9
Calcium hydroxide, $Ca(OH)_2$	350	40.3
Calcium carbonate, $CaCO_3$	106	12.2
Magnesium carbonate, $MgCO_3$	3	0.3
Lead hydroxide, $Pb(OH)_2$	6	0.7
Organic and volatile	176	20.4
Total Solids	868	100.0
Free carbon dioxide, CO_2	None	
Lead, Pb	5—Included above as $Pb(OH)_2$	
Zinc, Zn	None	
Copper, Cu	None	
Ammonia, NH_3	Trace	
Nitrite, NO_2	Trace	
Nitrate, NO_3	9—Included above as $NaNO_3$	
Acetate, $C_2H_3O_2$	Trace	
Sulfide, S	None	

pH value (electrometric-hydrogen electrode)—11.7
pH value (electrometric-quinhydrone electrode)—above limit of instrument
pH value (Calorimetric)—12.0

TABLE 2—Chemical Analysis of Water from a Continuous 4-Inch Precast Concrete Duct in a Second Concrete Tunnel

MATERIAL	Parts of Million	Percent of Total Solids
Silica, SiO_2	2	0.3
Iron and aluminum oxides, Fe_2O_3-Al_2O_3	4	0.6
Sodium chloride, NaCl	18	2.7
Sodium sulfate, $NaSO_4$	18	2.7
Sodium Nitrate, $NaNO_3$	12	1.8
Sodium hydroxide, NaOH	26	3.8
Calcium hydroxide, $Ca(OH)_2$	504	74.3
Calcium carbonate, $CaCO_3$	45	6.6
Magnesium carbonate, $MgCO_3$	3	0.4
Lead hydroxide, $Pb(OH)_2$	8	1.2
Organic and volatile	38	5.6
Total Solids	678	100.0
Free carbon dioxide, CO_2	None	
Lead, Pb	7—Included in the above as $Pb(OH)_2$	
Zinc, Zn	None	
Copper, Cu	None	
Ammonia, NH_3	None	
Nitrite, NO_2	Trace	
Nitrate, NO_3	9—Included in the above as $NaNO_3$	
Acetate, $C_2H_3O_2$	None	
Sulfide, S	None	

pH value (electrometric-hydrogen electrode)—11.8
pH value (electrometric-quinhydrone electrode)—above upper limit of instrument
pH value (colorimetric)—11.9

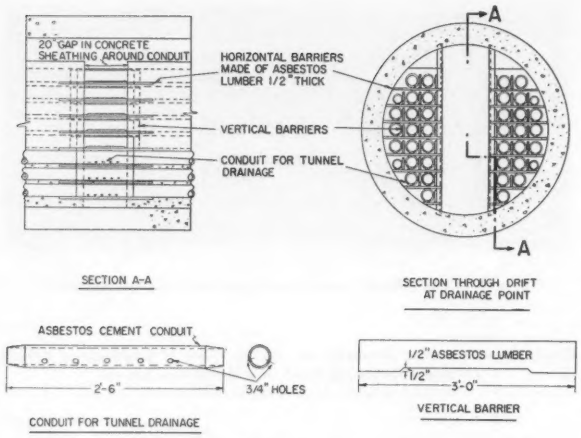

Figure 4—Method of draining conduits in tunnels.

TABLE 3—Chemical Analysis of Water From a Continuous 5-Inch Asbestos Cement Duct in a Concrete Tunnel

MATERIAL	Parts of Million	Percent of Total Solids
Silica, SiO_2	4	0.5
Iron and aluminum oxides, Fe_2O_3-Al_2O_3	6	0.7
Sodium chloride, NaCl	18	2.1
Sodium sulfate, Na_2SO_4	16	1.8
Calcium hydroxide, $Ca(OH)_2$	683	78.7
Calcium carbonate, $CaCO_3$	60	6.9
Calcium sulfate, $CaSO_4$	16	1.8
Lead hydroxide, $Pb(OH)_2$	39	4.5
Organic and volatile	26	3.0
Total Solids	868	100.0
Free carbon dioxide, CO_2	None	
Lead, Pb	33—Included above as $Pb(OH)_2$	
Zinc, Zn	None	
Copper, Cu	None	
Ammonia, NH_3	Trace	
Nitrite, NO_2	Trace	
Nitrate, NO_3	None	
Acetate, $C_2H_3O_2$	None	
Sulfide, S	None	

pH value (electrometric-hydrogen electrode)—11.7
pH value (electrometric-quinhydrone electrode)—Above limit of instrument
pH value (colorimetric)—11.7

believed that the sodium hydroxide originated from the sodium chloride used during the winter months for the removal of snow and ice from streets and bridges.

Chemical analyses indicated that the cable sheath corrosion in the continuous conduits was caused by the presence of large amounts of calcium hydroxide. It is an established fact that water containing calcium hydroxide in the concentrations found in most of these conduits will cause severe corrosion of lead sheathed cables. Tables 1, 2 and 3 give typical examples of chemical analyses of water from the continuous ducts. Tables 1 and 2 show analyses of water from continuous, 4 inch, precast concrete ducts in two tunnels. Table 3 shows analysis of water from a continuous, 5 inch, asbestos cement duct in another tunnel.

Chemical analyses given in these tables show that a large percentage of the total solids in the water was calcium hydroxide. The water also contained dissolved lead.

Corrective Measures

Attempts were made to dilute and reduce the concentrations of calcium hydroxide in the continuous conduits by a series of special water treatments. These treatments consisted of pumping the water from the tunnels, flushing out the vacant ducts and passageways, pumping out the flushing water and refilling the tunnels with city water. No practical method was devised whereby the ducts containing cables could be flushed. The water treatments were only slightly, if at all effective in reducing the concentration of hydroxides in the ducts occupied by cables. Chemical analyses of water from vacant ducts showed that any effective reduction in the concentration of hydroxides by the water treatments was of short duration.

In one tunnel the water was removed and the vacant ducts were treated with carbon dioxide at several different times. As in the case of the water treatments, the beneficial results were of short duration and not effective in ducts which contained cables and from which the water was not removed.

Because these treatments were ineffective in reducing the concentration of hydroxides and the rate of cable sheath corrosion, the possibility of providing some type of drainage for the continuous conduits was considered. It was desired that when the tunnels were pumped out, the contaminated water in the conduits would be removed and be replaced with fresh water when the tunnels were refilled with city water.

Methods Used for Draining Continuous Conduits in Tunnels

Drainage was provided for the continuous conduits in the tunnels by breaking out the conduits for a short distance adjacent to the bends in the lower ends of the drifts, and installing a 30 inch section of asbestos cement duct in each of the continuous ducts. Two rows of ¾ inch holes on 4 inch centers were drilled in the special sections, with a row of holes in each bottom quadrant, spaced 45 degrees from the vertical plane. Where ducts contained cables, the special sections of asbestos cement ducts were split. Asbestos lumber, ½ inch thick, was placed between each horizontal row of ducts at the points where the asbestos cement duct sections were installed, and vertical barriers of the same material were placed on the side of each duct. Small portions of these vertical barriers were cut away on the lower edges a distance of 20 inches. This was done to permit free passage of water out of or into the continuous ducts. The ends of the special duct sections and asbestos barriers were concreted in, leaving 20 inch gaps in the concrete sheathings around the duct banks. Figure 4 illustrates the method used to provide drainage for the continuous conduits.

Drainage has been provided for the conduits in 14 of the 15 tunnels which contain continuous conduits on the underground cable plant. In one tunnel, which is one of the two shared by a telephone company, the open passageway contains a large city water main. The presence of this water main makes it very difficult to install conduit drainage in the tunnel because of the lack of working space. After corrosion of

lead sheaths caused failure in 3 of the 5 cables, the cables at this location were replaced with special, double sheathed cables. Evidence of cable sheath corrosion was found on all the removed cables at the time of this replacement. Recent installation of cables in this tunnel has been made with lead-sheathed cables which had protective neoprene jackets over the sheaths. It is proposed that similarly protected cables be used for future installation at this location.

Corrective Measures Following Conduit Drainage

Following installation of conduit drainage, when the tunnels were given water treatments, the contaminated water was removed from the ducts containing cables. These ducts were refilled with fresh water when the tunnels were refilled with city water. In some tunnels the treatments were quite effective in reducing the concentration of hydroxides and in lowering the pH values. In other tunnels they were less effective and the benefits were of shorter duration. It was necessary to pump and flush some of the tunnels as many as three times a year to reduce the pH values and the concentration of hydroxides.

As the water treatments were continued a decided improvement in the chemical composition of the duct water occurred, and special water treatments were needed less frequently. Eventually, chemical analyses of the duct water showed no calcium hydroxide present and the pH values were greatly reduced.

Since elimination of the calcium hydroxides in the continuous conduits, the rate of cable failures due to corrosion in the tunnels has decreased and failures due to calcium hydroxide have caused less trouble. Recent chemical analyses of water from the continuous conduits show that the concrete used in these tunnels has now cured sufficiently to eliminate further corrosion of the cable sheaths caused by calcium hydroxide from this concrete.

Figures 5 and 6 give the histories of two tunnels on the underground cable plant, including the time of tunnel construction, installation dates of continuous conduits and the dates conduit drainage was provided. The curves show the frequency and number of special water treatments prior to and following installation of conduit drainage. They also show the results obtained by the replacement of the contaminated water in the conduits with fresh water and indicate the time that these water treatments cured the surrounding concrete to the point where the cable sheaths were no longer subjected to corrosion by calcium hydroxide.

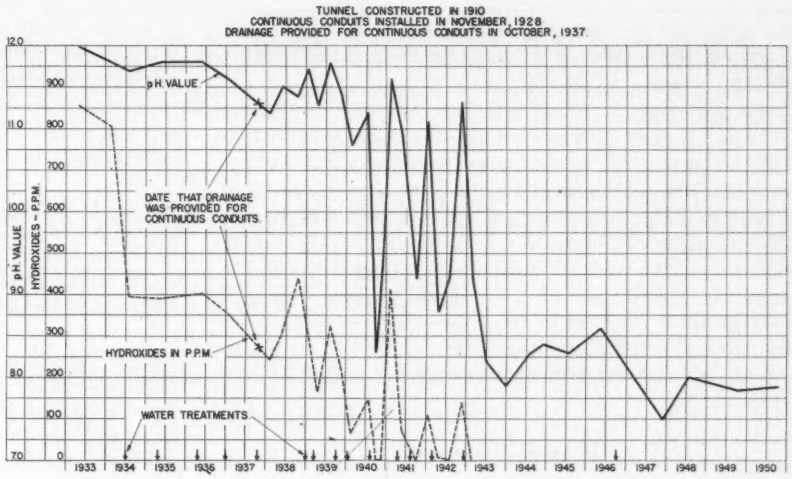

Figure 5—Hydroxides in parts per million and pH values for water from continuous conduits in a concrete tunnel.

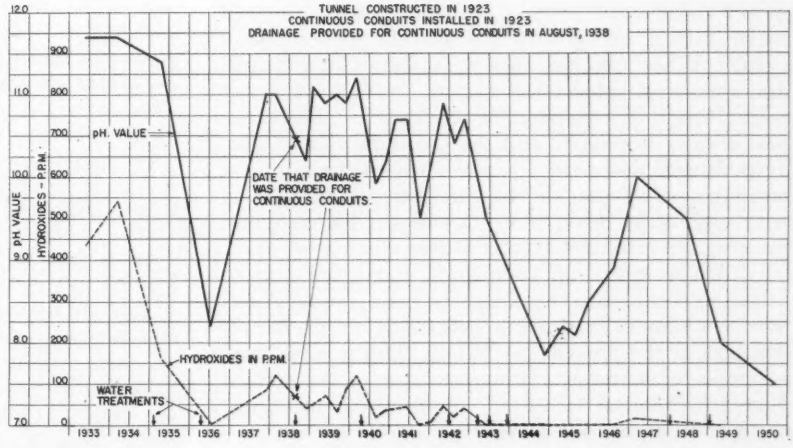

Figure 6—Hydroxides in parts per million and pH values for water from continuous conduits in a second concrete tunnel.

Early Practices

Originally when a new tunnel was constructed or new conduits were installed in existing tunnels, no special precautions were taken to cure the concrete used in the new work prior to the cable installation. In many cases following construction work, the tunnels were cleaned and flushed and allowed to fill with water by seepage.

When the conduits were not continuous, the water was pumped from the tunnels at frequent intervals for the installation or removal of cables. Any calcium hydroxide which may have been present was removed by these pumpings. Also, the heating of the conduits by cable loading caused circulation of water in the open conduits which tended to dilute the concentration of calcium hydroxide and to cure the concrete effectively.

The continuous conduits eliminated the necessity for removing the water from the tunnels to install or remove most cables. However, the water is re-

moved from the tunnels prior to pulling in of large, high-voltage cables, to permit prelubrication of the ducts.

In the event a tunnel was pumped out, the water that had seeped into the continuous conduits through the incompletely cured concrete would not be removed. The continuous conduits also restricted the free circulation of water, and the water which was driven off by evaporation due to heating of the cables was replaced by additional water seeping through the concrete sheathings and duct walls. This resulted in a gradual increase in the concentration of calcium hydroxide in these conduits. Restriction of free water circulation also retarded the curing of the surrounding concrete.

Present Practices

In recent years, measures have been adopted to cure properly all concrete which is used in connection with the installation of underground lead sheathed power cables. All precast concrete conduit is well cured before being installed on the underground system. When new conduits are installed in a tunnel, drainage is provided for the conduits. Following any major concrete construction work in a tunnel, the passageway is cleaned and the passageway and conduits flushed and held dry and open to the air for a minimum of 30 days. The structure is then filled with city water for two weeks, again pumped out, flushed, and refilled with city water.

If, due to operating conditions, it is necessary to install cables before the complete curing process has been completed, the curing process is continued regardless of the presence of cables. Thirty days later a sample of water is taken from one of the vacant ducts for chemical analysis to determine if additional curing treatments are necessary.

This procedure is sufficient, in most cases, to cure the concrete effectively so the concentration of calcium hydroxide in the continuous conduits is kept within satisfactory limits. Water analyses are made at intervals following all concrete construction work in tunnels. If these analyses indicate a calcium hydroxide concentration considered to be corrosive to lead, the tunnels are given special water treatments. The author's experience has indicated that corrosion of lead becomes serious in calcium hydroxide solutions at pH values of 11.4 and higher. Solutions containing between 150 and 200 parts per million of calcium hydroxide will usually show pH values of about 11.4.

These water treatments are very effective in reducing the concentration of calcium hydroxide, if the concrete has been sufficiently cured at the time of installation and if facilities have been provided for the free movement of water out of or into the continuous conduits.

Prelubrication of Conduits in Tunnels

When a large, high-voltage, lead sheathed cable is to be pulled into a tunnel, the water is removed from the tunnel and 25 pounds of a soap-stone and mineral oil compound is placed within the duct at each end of the tunnel in the swabbing operations. Twenty-five pounds of the compound is placed within the duct ahead of the cable. In addition, pulling grease is applied to the cable as it is drawn in, so that the cable is covered with a layer of grease about $\frac{1}{16}$ inch thick. This amounts to about eight pounds of grease per 100 feet, per one inch of cable diameter. Experience has shown that in moderate corrosive environments, the rate of corrosion on a lead sheathed cable which has been well coated with a good pulling grease is much less than on a cable which has had only enough grease applied to provide lubrication.

Conclusion

The cable operating record of this utility company shows that lead sheathed power cables may be operated in continuous concrete ducts and in ducts of other non-metallic materials encased in concrete and located in wet tunnels without serious corrosion due to calcium hydroxide. Utilization of properly designed conduits and the taking of precautions to cure the concrete structures sufficiently before installing the cables will reduce corrosion. If operating conditions are such that adequate curing of the concrete before installation of cables is impossible, the surrounding concrete may be cured effectively by providing facilities for circulation of air or hydroxide-free water.

The operating experience of this utility company also indicates that it is economically justifiable to incorporate in the design of concrete structures in tunnels which are to contain lead sheathed cables, provisions for effectively curing the concrete. When it is not possible to pre-cure the concrete and no provisions have been made in the conduit design for its curing in wet tunnels after cable installation, it is considered advisable to install cables which have protective jackets over the sheaths. Otherwise corrosion of the cables due to calcium hydroxide may result.

Any discussions of this article not published above will appear in the June, 1956 Issue.

Publication 56-7

Collection and Correlation of High Temperature Hydrogen Sulfide Corrosion Data*

A Contribution to the Work of NACE Task Group T-5B-2 on Sulfide Corrosion At High Temperatures and Pressures in the Petroleum Industry from: The M. W. Kellogg Co., New York, N. Y., by G. Sorell and W. B. Hoyt.

Abstract

Corrosion by gas mixtures containing hydrogen sulfide at elevated temperatures is reviewed, with particular emphasis on the types of environments present in catalytic reforming and desulfurizing units of petroleum refineries. Data compiled from the published literature, from laboratory and field tests, as well as from pilot and commercial plant experience are summarized and correlated.

Within the general limits of conditions existing in these types of units, corrosion is shown to depend primarily on temperature and hydrogen sulfide partial pressure. Summary curves showing corrosion rates as functions of these two variables are presented as a guide for equipment design.

The corrosion resistance of carbon steel and chrome-moly alloys steels is approximately equal in the environments studied; the 12 Cr stainless steels offer slight improvement but their performance is erratic. The 18 Cr-8 Ni stainless steels possess excellent resistance except under the most severe service conditions. Aluminum coatings are practically immune to hydrogen sulfide attack. There is, however, insufficient experience to appraise their permanence in prolonged service.

The nature and mechanism of hydrogen sulfide corrosion is discussed with special emphasis on the properties of sulfide scales.

Introduction

SEVERE CORROSIVE attack by hydrogen sulfide bearing gas mixtures at elevated temperatures has been experienced recently on several catalytic reforming and desulfurizing units in petroleum refineries. In view of the increasing number of installations of these types of units, the attendant corrosion problem is of vital concern to the refining industry.

The nature of this corrosion differs sharply in two important aspects from that long experienced in processing sour stocks in older type units such as crude distillation, thermal and catalytic cracking, thermal reforming, coking, etc. First, severe attack occurs at comparatively much lower levels of sulfur content, and secondly, the chrome-moly steels heretofore considered effective in resisting "sulfur attack" offer no improvement over plain carbon steel. Experience indicates that chromium-nickel stainless steels or aluminum coatings appear to be the only economically attractive materials capable of withstanding the more aggressive environments.

The apparent cause for this difference in corrosion behavior is attributed to the more severe action of hydrogen sulfide, especially at high pressures, as compared to that of organic sulfur compounds such as mono- and disulfides, mercaptans, and thiophenes. In the conventional refining processes previously named, only a small portion of these sulfur compounds is converted to hydrogen sulfide; in catalytic reforming and hydrodesulfurizing processes the combined action of the catalyst and hydrogen present may result in almost complete breakdown of organic sulfur compounds to hydrogen sulfide.

The phenomenon of high temperature hydrogen sulfide corrosion is currently being studied in experimental investigations by several companies and by the collection and evaluation of service experience from commercial operation. This compilation, correlation and critical review of pertinent data is offered in order to contribute to the understanding and solu-

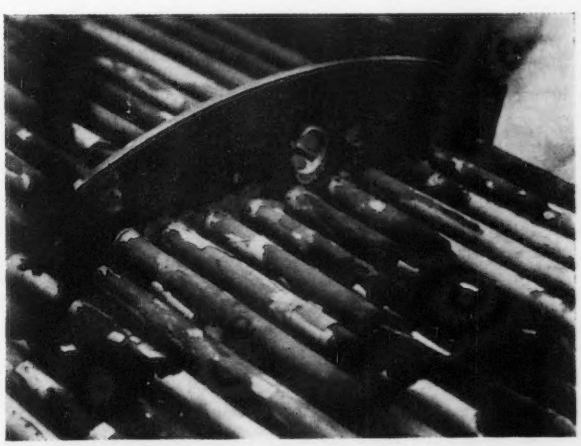

Figure 1—Sulfide scale formation on 5 Cr-½ Mo tubes of Catformer reactor effluent exchanger after six months operation at 870 F and 0.16 psia hydrogen sulfide partial pressure. The corrosion on the outside tube surface amounted to about 0.04 inches per year (B-10).

★A paper presented at the Twelfth Annual Conference, National Association of Corrosion Engineers, New York, N. Y., March 12-16, 1956.

tion of this corrosion problem. The information available was obtained both from the published literature (A-series) and from private sources (B-series). It covers a wide variety of laboratory results, pilot plant testing and refinery experience.

Charactertistics of Sulfide Scales

In several catalytic reforming and desulfurizing units the first warning of accelerated high temperature corrosion was an increase in pressure drop through the catalyst beds in the reactors. This was found to have been caused by an accumulated layer of scale on top of and interspersed in the catalyst. Subsequent inspection has revealed this same scale to be present on all of the metal surfaces of the high temperature equipment exposed to the process gases. These scales are the typical product of high temperature corrosion by hydrogen sulfide on steels. Their characteristics are described in the following sections:

Appearance of Scale

The typical appearance of sulfide scales is depicted in Figure 1 which pictures the brittle, flaky, multilayered scale that formed on the 5 Cr–½ Mo tubes and the 12 Cr baffle exposed to hot reactor effluent. The color and texture of the sulfide scale as observed in catalytic reforming units varies considerably, ranging from a bright silvery or golden appearance to a dull grey or black. The metallic appearing scales are predominantly present as brittle surface layers. The lower layers are generally composed of the darker scale more generally associated with corrosion by mixed sulfur compounds.

Physical Properties of Scale

The physical properties of sulfide scales formed on steels render them ineffectual as protective barriers against further corrosion. Wilson and Bahlke (A-52) and Dittrich (A-63) conclude that scale formation reduces the attack of the underlying metal to a limited degree, but a number of other investigators (A-18, A-34, A-68) are of the opinion that sulfide scales are entirely non-protective.

The failure of the scale to stifle or appreciably reduce corrosion is attributed to three detrimental properties—permeability, brittleness and lack of adherence. The latter two are closely related inasmuch as a cracked or embrittled scale tends to spall (A-29, A-62, A-63, A-65), thus exposing fresh metal to the corrosive medium. There is some limited evidence that the scale tends to remain intact provided it is maintained in compression, as on the inside surface of furnace tubes (B-11).

Kubaschewsky and Goldbeck (A-67) attribute the non-protective nature of sulfide scales to their high volume ratio, this being defined as the volume of metal sulfide formed to the volume of equivalent metal consumed. The volume ratios of the monosulfide scales commonly formed on carbon and alloy steels range from 2.5 to 4.0 (A-66, A-67, B-11) which is appreciably higher than values between 1.3 and 2.0 considered representative of more protective scales such as oxides. High volume ratios are believed to be detrimental to the formation of a durable and protective scale because the high residual stresses inherent in bulky scales promote brittleness.

The melting point of scale is also an important factor in determining corrosion resistance, particularly at higher temperature levels. The poor resistance of nickel-rich alloys to sulfur compounds has been connected with the low melting point (1190 F) of the nickel-nickel sulfide eutectic (A-1, A-36, A-62, A-67). Conversely, the excellent resistance of Fe-Al alloys has been attributed in part to the high fusion point of the sulfide layer formed (A-62).

In general it is found that sulfide scales formed on stainless steels are tougher and more adherent than those formed on carbon and low alloy steels (A-29, A-31, B-10). With Fe-Al alloys as well, the scale formations observed have been fairly tight and adherent (A-62, A-65). It appears therefore that the excellent resistance to hydrogen sulfide attack exhibited by stainless and Fe-Al alloys can be at least partially attributed to the more protective value of their corrosion products.

Chemical Composition of Scale

Chemical analysis of corrosion products removed from a number of catalytic reforming and desulfurizing units shows them to consist principally of a mixture of iron sulfide and iron oxide (B-2, B-8, B-10, B-12, B-16). The relative proportions of each material is dependent on the atmosphere to which the equipment was exposed directly prior to inspection. Lengthy periods of regeneration produce nearly pure oxides (B-16), whereas the total absence of regeneration causes the scale to remain entirely in the form of sulfides (B-10). A light regeneration burn produces a fairly evenly divided mixture of iron oxide and iron sulfide (B-12). The interconvertibility of sulfides and their corresponding oxides during the reaction-regeneration cycle can be predicted from a thermodynamic analysis.

The majority of investigators report that the sulfide corrosion product of iron and iron alloys is predominantly in the form of the monosulfide. The bright and shiny appearance of scale occasionally observed (A-67, B-11) probably is due to a thin surface layer of FeS_2 which has a metallic luster.

Experimental evidence indicates that the chemical composition of sulfide scale formed on alloys is not constant throughout its thickness. Rickett and Wood (A-61) and Dittrich (A-64) demonstrated that the inner zones are much richer in alloy content than the outer ones, and are in fact richer than the base metal proper. The outermost portions of sulfide scales are composed predominantly of iron sulfide regardless of the chrome and/or nickel content of the parent metal. This has been verified in the field. The metallic portion of scale scraped off an 18 Cr–8 Ni Catformer shroud showed a composition of 96 Fe–1.5 Cr–2.5 Ni (B-10). The fact that sulfide scales of ferrous alloys contain only small amounts of the alloying elements makes it virtually impossible to estimate the comparative performance of carbon and alloy steels from an analysis of loose corrosion products.

The experimental fact that the sulfide corrosion products of all ferrous alloys are composed primarily of FeS has been utilized by the authors for converting corrosion measurements reported as weight gain (due to sulfidation) to metal loss in inches per year.

Mechanism of Scale Formation

The mechanism of high temperature sulfide corrosion long recognized as a complex phenomenon has been studied by a number of researchers. Rickett and Wood (A-16), among the earliest to investigate the rate of scaling and its related factors, analyzed the corrosion reaction as a problem in classical reaction kinetics. Two rate determining factors are postulated: (1) The velocity of chemical reaction (sulfidation) at the interface between the reacting phases, and (2) The rate at which the reactants or products of the reaction reach or are removed from the interface. The mechanism of mass transfer involves diffusion processes which are believed to be the governing factors in high temperature hydrogen sulfide attack. This is deduced from the small temperature coefficients observed with the corrosion reaction as compared to those normal for processes where chemical reactions are controlling.(1)

In general, the rate of diffusion depends on a number of variables which cannot readily be evaluated quantitatively from a purely theoretical approach. Among these are included such factors as the nature of the substances which are diffusing, the chemical composition, physical structure and thickness of the medium through which diffusion takes place, and the solubility of the reactants in the scale. The specific diffusion processes involved appear to be the migration of sulfur inward through the scale, and that of metal atoms outward. As evidenced by the alloy impoverished outer scale zones (A-61, A-64), the iron apparently diffuses more rapidly than either chromium or nickel.

In a more recent study, Geld and Esin (A-36) suggest several factors in addition to the relative magnitudes of diffusion coefficients, which they consider as playing an important part in the corrosion mechanism. These factors include the more modern concepts of crystal lattice energies of the respective sulfides, the types of lattice structures, the ratios of ion sizes, and lattice parameters. The latest theory, developed by Kubaschewsky and Goldbeck (A-67), introduces semi-conductor physics as yet another

(1) In the next section the corrosion rate is shown to double approximately with every 100 F rise in temperature. For chemical reactions, the rate is generally more temperature dependent and commonly increases by a factor of 3 or 4 for a similar temperature increment.

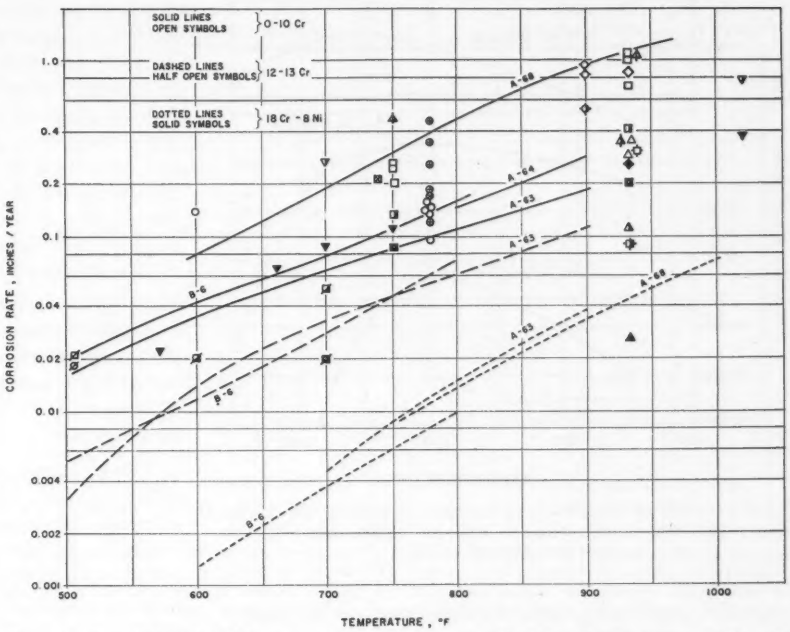

Figure 2—Correlation chart showing corrosion of steels as a function of temperature at 15 psia hydrogen sulfide partial pressure.

TABLE 1—Code for Figure 2 Symbols

SYMBOL	MATERIAL	SOURCE	REFERENCE
———	0-6 Cr	Laboratory	A-63*
———	10 Cr	Laboratory	A-64*
———	0-7.5 Cr	Laboratory	B-6
———	C.S.	Laboratory	A-68
— — —	13 Cr	Laboratory	A-63*
— — —	13 Cr	Laboratory	B-6
- - - - - -	18 Cr - 8 Ni	Laboratory	A-63*
- - - - - -	18 Cr - 8 Ni	Laboratory	B-6 *
- - - - - -	18 Cr - 8 Ni	Laboratory	A-68
○	0-7 Cr	Field Test	B-8
⊕	C.S.	Equipment	B-7
⊗	C.S.	Laboratory	B-5
◇	0-8 Cr	Laboratory	A-23
◈	12 Cr	Laboratory	A-23
⊘	C.S.		A-33
□	0-9 Cr	Laboratory	A-43
◨	12 Cr	Laboratory	A-43
■	18 Cr - 8 Ni	Laboratory	A-43
⊠	Iron	Laboratory	A-52
⊡	C.S.	Laboratory	A-31
◧	12 Cr	Laboratory	A-31
⊠	C.S.		A-13
◪	12 Cr		A-13
◩	18 Cr - 8 Ni		A-13
◇	C.S.	Laboratory	A-46
◆	18 Cr - 8 Ni	Laboratory	A-46
△	0-1 Cr	Laboratory	A-18
◭	12 Cr	Laboratory	A-18
▲	18 Cr - 8 Ni	Laboratory	A-18
▽	12 Cr	Laboratory	A-35
▼	18 Cr - 8 Ni	Laboratory	A-35
⧋	Iron	Laboratory	A-65
⧋	12 Cr	Laboratory	A-65

* The corrosion rates plotted in Figure 2 are 50% of the experimental values; these adjustments were made to compensate for prolonged exposures.

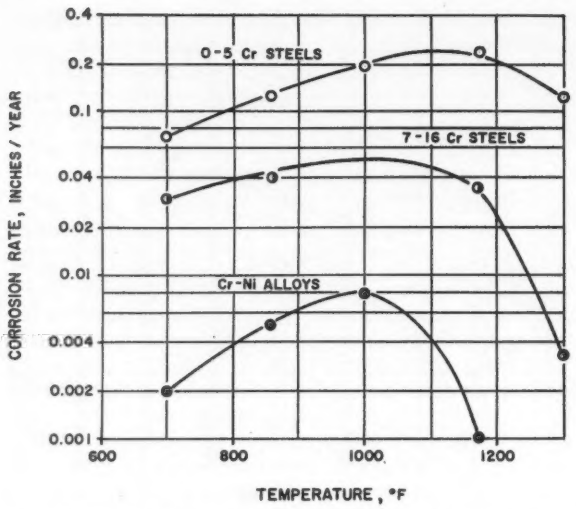

Figure 3—Effect of temperature on corrosion of steels at 0.1 percent volume (0.5 psia partial pressure) hydrogen sulfide and 485 psig hydrogen pressure (A-29).

approach which may shed further light on the mechanism of sulfidation.

Although these various speculations about the corrosion process are of definite theoretical interest, it is not expected that they will make immediate and significant contributions to the practical solution of this corrosion problem. It is doubtful that the scant physical data on the behavior of various sulfides currently available are sufficient to permit the systematic application of theoretical principles to the accurate evaluation and development of sulfur resistant materials. As a result, the development of new and better alloys and surface coatings is likely to remain dependent primarily on empirical results.

Environmental Factors Affecting Corrosion

In the introduction it is stated that heavy sulfidation of catalytic reforming equipment is experienced at hydrogen sulfide concentrations corresponding to total sulfur contents far below those commonly associated with "sulfur attack." This point is well illustrated by some recently published findings on hydrogen sulfide corrosion. Backensto et al (A-29) report that hydrogen sulfide concentrations as low as 0.05 percent by volume attack carbon and low chromemoly steels at a rate exceeding 0.2 inches/year. By comparison, ordinary petroleum fractions containing similarly low sulfur levels are considered entirely non-corrosive regardless of temperature. Experience indicates that combined sulfur may be tolerated in quantities up to about 0.5 percent by weight (i.e., ten times that quoted above) without causing corrosion difficulties.[2]

In view of this wide discrepancy in corrosivity between the long recognized "sulfur attack" and the newly experienced hydrogen sulfide corrosion, it was first speculated that some unknown factor or factors were responsible for accelerating the rate of attack in catalytic reformers and desulfurizers. One of these factors suspected of being a "corrosion catalyzer" is the presence of hydrogen; another, the alleged promotive action of some trace impurity such as chloride. These views have been largely abandoned and the currently prevalent opinion, shared by the authors, is that the high scaling rates are due primarily to the exceptionally corrosive nature of hydrogen sulfide at elevated temperatures.

In the remainder of this section the various environmental factors generally considered in corrosion studies are discussed individually.

Temperature

Temperature is considered to be the most important variable; nearly all investigators report a rapid increase of corrosion with rising temperature. The majority of data indicates that a temperature rise of 100 F can be expected to approximately double the rate of attack. This relationship is illustrated by the exponential curves in Figure 2 (for code see Table 1) which can be expressed by the following approximate equation:

$$\text{Corrosion Rate (Ipy)} = Ke^{0.007t}$$

where K is a constant and t the temperature in degrees F. Although this specific function does not satisfy all the data examined, every investigator except one reports an increase of corrosion with rising temperature. The notable exception to this trend has been described by Backensto et al (A-29). As can be seen from Figure 3, the rates go through a maximum above 1000 F. No satisfactory explanation for this apparently anomalous result has been advanced. Maximum corrosion rates in the range from 700 to 900 F have been frequently experienced on units processing sour stocks (A-24, A-33, A-36), but the accepted explanation for this phenomenon applies only to corrosion by oganic sulfur compounds.[3]

Hydrogen Sulfide Content

The collected data show without exception that under constant temperature conditions the corrosion rate increases with higher hydrogen sufide contents. In attempting to relate the rate of attack to some measure of hydrogen sulfide content, it becomes apparent that the commonly used measures (i.e., weight, volume or mol percent[2]) do not correlate as well as does the partial pressure of the hydrogen sulfide in the gas mixture. This conclusion is most clearly illustrated by comparing Figures 4, 5 and 6; Figure 6 shows that the corrosion rate remains

(2) Lacking specific corrosion data, it is common practice to place the dividing line between "sweet" and "sour" stocks within the range from 0.5-1.0 percent sulfur by weight. It is of interest to note that recent experiments with crude oils (A-26) indicate that the amount of hydrogen sulfide liberated by the thermal decomposition of organic sulfur compounds is a far more reliable corrosion criterion than the initial quantity of these compounds present in the oil.

(3) It is speculated that the temperature where peak rates are observed coincide with those at which a large portion of the organic sulfur compounds are thermally cracked. The hydrogen sulfide or elemental sulfur thus formed is thought to be so highly "reactive" at the instant of liberation, as to overshadow the accelerating effect of a subsequent temperature rise on the rate of corrosion.

(4) Some refineries prefer to report hydrogen sulfide content in grains per 100 standard cubic feet, a unit directly proportional to mole or volume percent. (Grains sulfur/100 SCF) (0.0016) = Mol percent.

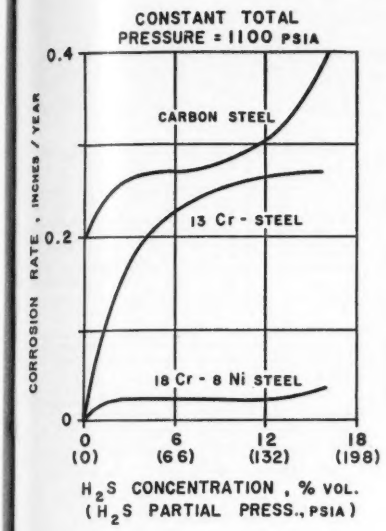

Figure 4—Effect of hydrogen sulfide concentration and partial pressure on corrosion of steels in hydrogen-hydrogen sulfide mixtures at 752 F and 1100 psia pressure (A-63).

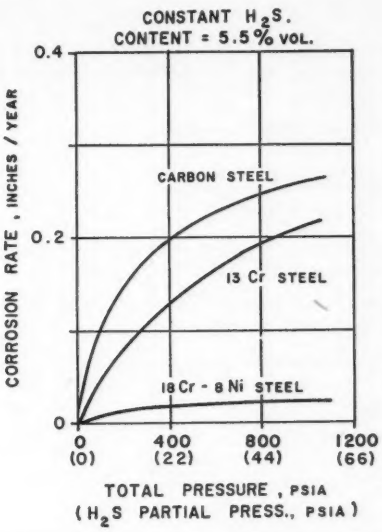

Figure 5—Effect of total and hydrogen sulfide partial pressure on corrosion of steels in hydrogen-hydrogen sulfide mixture at 752 F containing 5.5 percent hydrogen sulfide by volume (A-63).

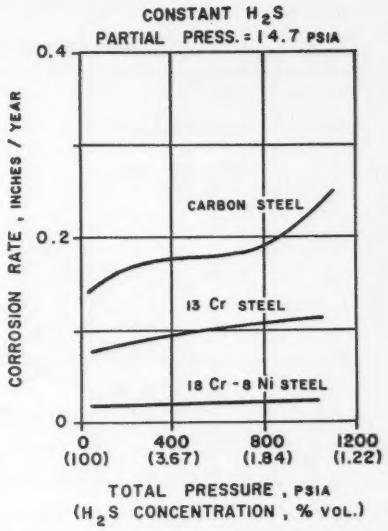

Figure 6—Effect of hydrogen sulfide concentration on corrosion of steels in hydrogen-hydrogen sulfide mixtures at 752 F and on hydrogen sulfide partial pressure of 14.7 psia (A-63).

nearly constant over a wide range of total pressures and hydrogen sulfide concentrations as long as the hydrogen sulfide partial pressure is kept constant.

The functionality between hydrogen sulfide partial pressure and corrosion rate is not readily discernible, probably because it is not consistent at all temperatures and concentrations. The correlation presented in Figure 7 (see Table 2 for code) suggests that the corrosion rate is almost directly proportional to the partial pressure of hydrogen sulfide, while some investigators (A-48, B-6) postulate that the corrosion rate varies as some fractional power of the partial pressure of hydrogen sulfide. Judging by the different shapes of curves in Figures 4, 5, 8 and 9, apparently no single mathematical relationship fits all conditions.

The generally good correlation between corrosion and hydrogen sulfide partial pressure appears to break down at small hydrogen sulfide concentrations. This conclusion is brought to light by noting the large difference in corrosion rate predicted by Figures 8 and 9 for identical conditions of temperature (985 F) and hydrogen sulfide partial pressure (0.05 psia). For steels containing 0-5 percent Cr, Figure 8 predicts a rate of about 0.003 ipy (at 0.01 percent hydrogen sulfide), whereas Figure 9 gives a rate of 0.16 ipy (at 0.20 percent hydrogen sulfide). This discrepancy relates to the existence of threshold levels of hydrogen sulfide concentrations at around 0.005-0.01 percent, below which attack ceases altogether (A-29).

The danger of extrapolating experimentally determined correlations between corrosion rate and hydrogen sulfide concentration (or partial pressure) is also brought out in Figure 10. Here the effect of hydrogen sulfide content is shown to be also temperature dependent. At 500 F, there is an eight-fold increase in corrosion rate in going from 0.3 to 0.8 percent hydrogen sulfide, while at 600 F, there is no significant difference in rate for these two concentrations.

Pressure

The total pressure appears to be an important corrosion variable only inasmuch as it determines the partial pressure of the hydrogen sulfide in a given gas mixture. If the hydrogen sulfide concentrations are experimentally adjusted so as to maintain constant hydrogen sulfide partial pressure (as in Figure 6), raising the total pressure appears to have no accelerating effect on corrosion. On the contrary, inspection of Figures 8 and 9 indicates that for equal hydrogen sulfide partial pressures the rates at 485 psig total pressure are consistently smaller than those at lower total pressures. It is concluded that high total pressures as encountered in reforming and desulfurizing units (up to about 700 psig) do not intensify hydrogen sulfide corrosion.

Length of Exposure

The evidence collected indicates that the initial rate of attack is very high. It drops off rapidly during the first few hours but still may be fairly high after one day. For the next few days the rate continues to level off until at the end of about 100-200 hours, no further appreciable decrease is to be expected. The quasi-exponential shape of the rate-time curve has been fairly well established in recent experiments (A-29). All but one of the investigators of this phase of hydrogen sulfide corrosion agree that the initial rate of attack is considerably higher than that registered in the later stages of exposure (A-52, A-63, A-64, B-6).[5]

The experiments by Dittrich (A-63, A-64) show that the corrosion rates measured after 50 hours of

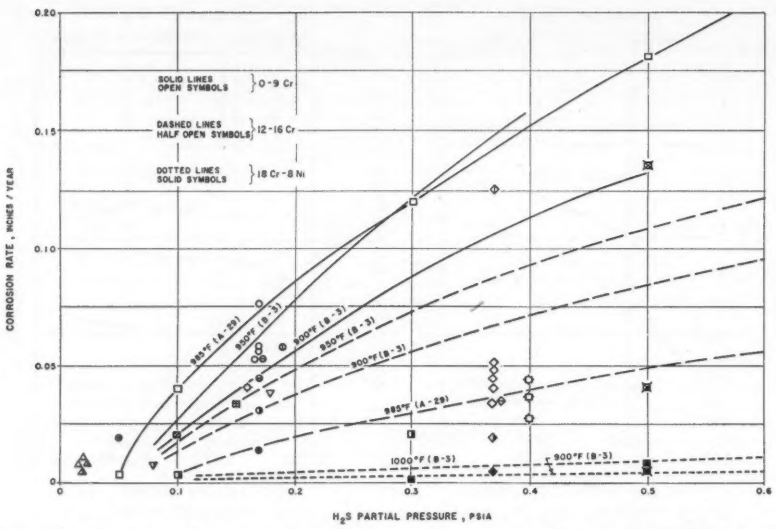

Figure 7—Correlation chart showing corrosion of steels at elevated temperatures (850-1050 F) and pressures (300-700 psig) as a function of hydrogen sulfide partial pressure.

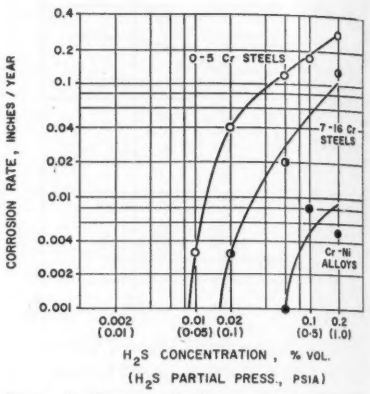

Figure 8—Effect of hydrogen sulfide concentration and partial pressure on corrosion of steels at 985 F and 485 psig hydrogen pressure (A-29).

TABLE 2—Code for Figure 7 Symbols

SYMBOL	MATERIAL	TEMPERATURE (°F)	TYPE OF DATA	REFERENCE
———	0-5 Cr	900-950	LABORATORY	B-3
— — —	12 Cr	900-950	LABORATORY	B-3
- - - - - -	18 Cr - 8 Ni	900-1000	LABORATORY	B-3
—□—	0-5 Cr	985	LABORATORY	A-29
— -▣- —	7-16 Cr	985	LABORATORY	A-29
- - -▣- - -	18 Cr - 8 Ni	985	LABORATORY	A-29
⊠	LOW Cr	950	EQUIPMENT	B-11
⊠	0-5 Cr	860	LABORATORY	A-29
⊠	7-16 Cr	860	LABORATORY	A-29
⊠	18 Cr - 8 Ni	860	LABORATORY	A-29
⌬	5 Cr	859-905	EQUIPMENT	A-29
⊞	2 Cr	1000	EQUIPMENT	B-12
○	0-9 Cr	950-1025	FIELD TEST	B-2
◐	12 Cr	950-1025	FIELD TEST	B-2
●	18 Cr - 8 Ni	950-1025	FIELD TEST	B-2
⊖	0-5 Cr	950-1025	FIELD TEST	B-2
⊗	0-2 1/4 Cr	900	EQUIPMENT	B-1
⊕	1 1/4 Cr	950	EQUIPMENT	B-1
◇	5 Cr	870	EQUIPMENT	B-10
◇	0-9 Cr	925	FIELD TEST	B-15
◈	12 Cr	925	FIELD TEST	B-15
◆	18 Cr - 8 Ni	925	FIELD TEST	B-15
◈	5 Cr	925	EQUIPMENT	B-14
◈	9 Cr	1000-1050	EQUIPMENT	B-14
▽	2 1/4-5 Cr	900	EQUIPMENT	B-4
▼	12 Cr	900	EQUIPMENT	B-4
△	5 Cr	900-1025	EQUIPMENT	B-16
▲	12 Cr	900-950	EQUIPMENT	B-16

exposure are about halt those obtained from tests terminated after 20 hours. British Petroleum (B-6) states that the experimental rates based on 48 hour tests (see Figure 11) can be reduced for prolonged exposures. This reduction of corrosion rate is more pronounced with stainless than with carbon or low alloy steels, a fact which appears logical in view of the more dense and tenacious scales formed on high alloy materials. It is doubtful, however, that there is any further reduction in rate after several hundred hours' exposure, although some claims to the contrary are on record (B-11).

Judging by the evidence at hand, short time corrosion tests yield exaggerated results which probably do not correctly reflect the behavior of the material in refinery service. In an effort to obtain more realistic estimates of corrosion rates, some adjustments were made, at least in those cases where exposure time was one of the variables studied (A-63, B-6). The specific modifications made in each case are described in the respective abstracts (see Appendices) as well as in Tables 1 and 3.

For the remainder of short time tests, no attempt was made to make similar adjustments, since it was felt that in the absence of any supporting data such adjustments would be purely arbitrary. The corrosion rates obtained from tests of less than about one day's duration should therefore not be taken at face value. Note for example the exceptionally high values derived from a series of five hour tests by Wellmann (A-39). As is evident from Figure 2, Wellmann's rates are about ten times greater than those reported by other investigators.

Cyclic Conditions

Cyclic conditions are considered to accelerate corrosion because they tend to deteriorate the sulfide scale which, though not impervious, is at least partially protective. The two types of cyclic conditions of greatest practical interest in catalytic reforming and desulfurizing processes where the catalyst is regenerated in situ are alternate heating and cooling, and exposure to alternate reducing and oxidizing atmospheres. Alternate heating and cooling is detrimental because the thermal stresses set up cause spalling of the scale (A-29, A-52, A-62). It is claimed that the distinctive layers observed in sulfide scales are caused by major temperature changes (B-11). The resulting stratified structure of the scale makes it inherently porous and crumbly. Exposure to successive reducing and oxidizing conditions also leads to scale deterioration, except in this case the lack of adherence is caused principally by chemical

(5) The notable exception to this trend was reported by White and Marek (A-18) who found initial corrosion rates to be slightly lower than those obtained after longer periods of time. They speculated that the thin but elastic scale formed shortly after exposure is a more effective corrosion barrier than the thick brittle scale characteristic of the later stages of attack.

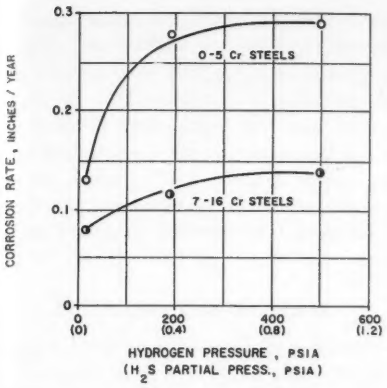

Figure 9—Effect of hydrogen pressure and hydrogen sulfide partial pressure on corrosion of steels at 985 F and 0.2 percent hydrogen sulfide by volume (A-29).

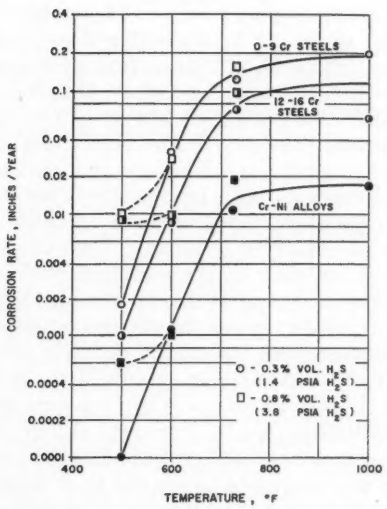

Figure 10—Effect of temperature and hydrogen sulfide content on corrosion of steels at 465 psig hydrogen pressure (A-29).

changes. It has been shown (B-8) that the sulfides and their corresponding oxides are interconvertible according to the following reactions:

$$FeS + O_2 \xrightarrow{\text{Regeneration}} FeO + SO_2$$

$$FeO + H_2S \xrightarrow{\text{Reaction}} FeS + H_2O$$

These changes cause the scale to become porous and eventually to flake off, thereby exposing fresh metal to rapid attack by the hydrogen sulfide bearing gases.

The hypothesis that alternate oxidation and reduction necessarily results in impaired corrosion resistance is not supported by all the evidence examined. Jackson et al (A-51) report no increase in attack in alternating oxidizing and reducing high temperature flue gas mixtures, nor for that matter

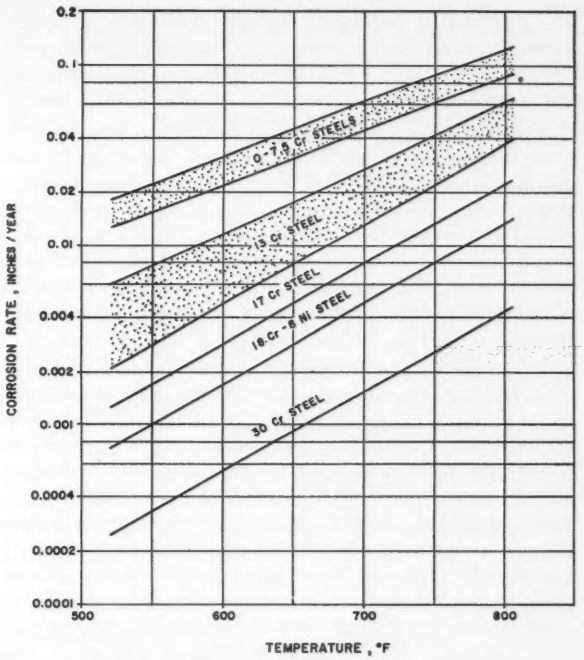

Figure 11—Effect of temperature on corrosion of steels by hydrogen sulfide at 6.0 psia partial pressure in hydrogen-hydrogen sulfide mixtures at atmospheric pressure (B-6).

under conditions of large temperature changes. British Petroleum (B-5) conducted a series of tests specifically designed to investigate the effect of alternate reaction-regeneration conditions on the rate of attack. No difference was discovered between the average corrosion rate in alternating and steady state conditions. These tests also showed that regeneration gases are non-corrosive, which is in agreement with common knowledge that high temperature corrosion by SO_2 is far less severe than that by hydrogen sulfide (A-12, A-23, A-51, A-62, A-68).

Diluent Gas

The nature of the diluent gas containing the hydrogen sulfide does not appear to have a marked effect on corrosion. This conclusion is not in agreement with the widely held opinion that strongly reducing atmospheres effectively promote hydrogen sulfide corrosion. The latter theory was first advanced by Dittrich (A-63) who attributes the sudden rise in the carbon steel corrosion curve at elevated pressure (see Figure 6) to the indirect effect of the hydrogen which supposedly renders the metal surface more susceptible to hydrogen sulfide attack. This conclusion appears unwarranted inasmuch as a similar rise in slope was also noted at constant hydrogen pressure, as shown on Figure 4.

Baukloh and Spetzler (A-65) also state that hydrogen promotes hydrogen sulfide corrosion, due supposedly to its destructive action on the metal grain boundaries with subsequent "loosening" of the crystal lattice. They base their conclusion that corrosion in hydrogen is generally higher than that in nitrogen atmospheres on the experimental findings

summarized in Tables 17 and 18. It should be noted, however, that these differences are significant only for the tests with Fe-Al laboratory alloys; they are inconclusive for those performed with chrome steels.

Socony Mobil (A-29) and British Petroleum (B-6) have investigated to a limited extent the effect of gas composition on corrosion. Socony's tests indicate that the substitution of nitrogen for hydrogen or dilution of the hydrogen with hydrocarbon vapors may suppress the rate to a minor extent. British Petroleum reports that the presence of hydrocarbon vapor in hydrogen sulfide bearing gas mixtures has no detectible influence on corrosion.

The limited data referred to are inconclusive for determining the degree which the various diluent gas mixtures affect the rate of attack. However, it appears that the presence of hydrogen plays at best a secondary role in promoting corrosion by hydrogen sulfide. The effect of hydrocarbon vapors on corrosion probably depends to a large extent on whether or not coking takes place, because coke deposits may act as effective corrosion barriers. On this assumption, the presence of hydrogen can be considered instrumental indirectly in accelerating hydrogen sulfide corrosion inasmuch as hydrogen-rich gases are known to suppress coke formation. This may possibly contribute to the more severe corrosion observed in catalytic reformers and desulfurizers as compared to conventional processes where coking is more prevalent.

Contaminants

The presence of small amounts of foreign substances such as water, chlorides or organic acids appears to have little or no effect on the rate of hydrogen sulfide attack. Of the six investigators reporting on the effect of moisture, three (A-29, A-31, B-6) claim that it tends to increase corrosion, two (A-18, A-57) that it slightly depresses the rate, and one (B-3) that it probably has no effect at all.

The possibly harmful effect of chlorides has been considered in connection with the practice of injecting chlorides in platinum reforming units for the purpose of rejuvenating the catalyst. From the limited information available (A-48, B-3, B-11), it is concluded that the presence of chlorides has no appreciable effect on high temperature hydrogen sulfide corrosion. On the contrary, the experimental findings reported by Prutton et al (A-48) show evidence that the addition of HCl vapors to hydrogen sulfide has a marked tendency to reduce rather than intensify corrosive attack.

The presence of other minor constituents such as organic acids or nitrogen compounds is not reported to have been investigated.

Metal Pre-Treatment and Turbulence

Metal pre-treatment is another of the factors suspected of influencing sulfide attack. Available data, however, do not support this theory. A series of tests conducted by British Petroleum (B-5) revealed that the initial presence or absence of mill scale on the steel does not affect the observed rate of scaling. Pre-treatment with either hydrogen or air has no detectible effect on the subsequent resistance to sulfidation (A-29).

Erosion produced by rapidly moving products and by suspended particles is considered to be an important factor in the wear of equipment (A-31). This conclusion is not borne out by the experimental results obtained by Socony Mobil (A-29); test runs covering a wide range of velocities revealed no significant difference in corrosion rate between stagnant and turbulent conditions.

Materials of Construction

In the previous section, high temperature hydrogen sulfide attack was analyzed in relation to environmental factors. This section is devoted to a discussion of the corrosion-resisting characteristics of constructional materials in these environments.

Carbon and Low Chrome Steels (0-10 Percent Cr)

Steels containing up to about 10 percent chromium have been shown to be no better than plain carbon steel in resisting high temperature hydrogen sulfide attack (A-2, A-29, A-30, A-63, A-64, B-2, B-3, B-6, B-8, B-10, B-13, B-15). This finding is of utmost significance because the low chrome steels (especially the 5 Cr—½ Mo grade[6]) are known and used widely for their resistance to high temperature "sulfur attack" by sour stocks in services such as crude topping, thermal and catalytic cracking, thermal reforming, coking, etc. In view of the excellent performance of the chrome-moly steels in processing high sulfur stocks (including heavy fractions containing about 5 percent combined sulfur), it is easily understandable that these steels were assumed to be generally resistant to all forms of high temperature sulfur attack, including that by hydrogen sulfide. This misconception has been strengthened by frequent references in the published literature to a single laboratory corrosion test, the results of which (see Ref. A-40) support the popular but incorrect belief that incremental additions of chromium to steel progressively improve its resistance to hydrogen sulfide attack.

It is interesting to note that some of the data on hydrogen sulfide corrosion show a directly opposite trend, namely that small additions of chromium actually impair the corrosion resistance of steel. This experimental fact is shown graphically in Figures 12 and 13, both of which illustrate the finding that the corrosion rate goes through a maximum at a chromium content of about 5 percent Cr. Some of the field data also point up the relative inferiority of low chrome steels compared to unalloyed steel (see Tables 22 and 31).

Intermediate Chrome Steels (11-13 Percent Cr)

The intermediate straight chrome steels, containing about 12 percent Cr have only moderately higher resistance to high temperature hydrogen sulfide at-

(6) The low chrome steels used in the refining industry generally contain 0.5-1.0 percent molybdenum to improve their high temperature strength and their resistance to temper brittleness. As regards hydrogen sulfide corrosion, presence of these small quantities of molybdenum is immaterial.

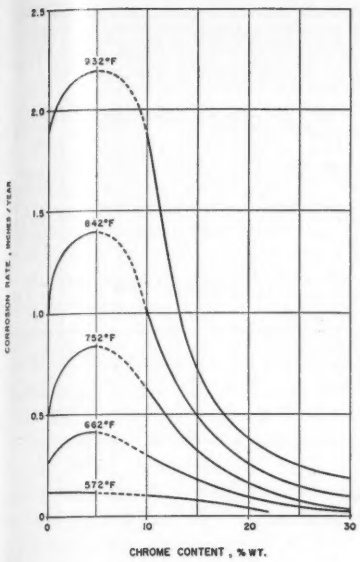

Figure 12—Effect of chrome content on corrosion of steels by 16 percent hydrogen sulfide by volume in hydrogen-hydrogen sulfide mixture at 1100 psia pressure (A-64).

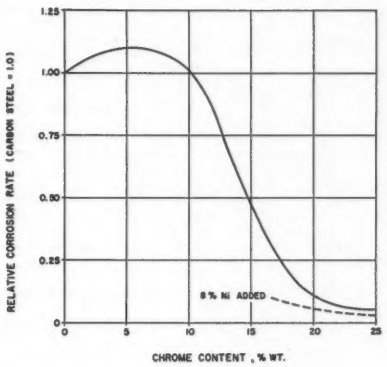

Figure 13—Relative corrosion rates of carbon, chrome and chrome-nickel steels in hydrogen-rich catalytic reformer gases at 500 psig pressure (B-3).

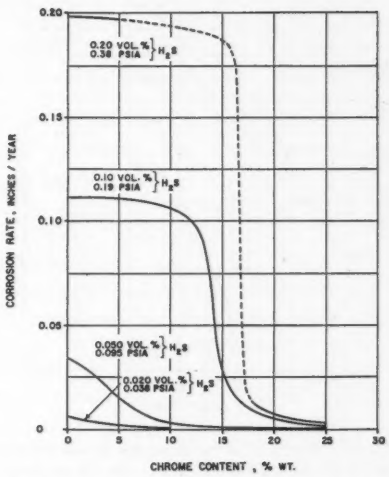
0.20 VOL. % H2S 0.38 PSIA
0.10 VOL. % H2S 0.19 PSIA
0.050 VOL. % H2S 0.095 PSIA
0.020 VOL. % H2S 0.038 PSIA
CORROSION RATE, INCHES / YEAR
CHROME CONTENT, % WT.

Figure 14—Effect of chrome content on corrosion of steels by hydrogen-hydrogen sulfide mixtures at 1175 F and 175 psig pressure (A-29).

tack than carbon and the lower chrome steels. In the range of conditions to be expected in and around catalytic reforming reactors, the 12 Cr steels are at best twice as resistant as carbon steels. Actual reformer plant experience reported by American Oil (B-2), Shell (B-15) and Sinclair (B-16) indicates about 80 percent improvement of 12 Cr steels over carbon or low chrome-moly steels.

In the higher ranges of hydrogen sulfide content, such as anticipated in desulfurization units, the 12 Cr steels appear to offer greater improvement relative to lower alloy materials (about 4:1) but this degree of improvement cannot be relied upon because of the widely fluctuating behavior of the 11-13 percent Cr steels. The variable performance of the 11-13 percent Cr steels is predictable from Figures 12, 13 and 14, all of which show the corrosion rate as a function of the chromium content. The slopes of the curves are very steep at around 12 percent Cr, indicating that minor variations in the alloy content have a large effect on corrosion resistance. A wide fluctuation of measured rates has been observed even in experiments where multiple specimens of the same 12 Cr steel have been tested under identical conditions (A-29).

The collected evidence indicates that a chromium content of about 12 percent can be considered "critical" inasmuch as it may or may not effect a significant improvement of corrosion resistance. Materials exhibiting this borderline behavior cannot be relied on to perform in a consistent and predictable manner, and average results are therefore a poor criterion for individual applications.

Straight Chromium Stainless Steels

Additions of chromium to steels in excess of about 12-15 percent provide effective protection against attack by hot gaseous hydrogen sulfide. In the approximate range from 15-25 percent Cr, incremental additions of chromium impart progressively greater corrosion resistance. Above a chromium content of about 25 percent, further additions cause no significant improvement. These conclusions are illustrated by the curves in Figures 11, 12, 13 and 14.

Although all investigators agree unanimously that chromium in larger quantities is an effective alloying ingredient, it is interesting to note that some of the data indicate that even smaller amounts are effective in certain instances. For example, the curves for 0.02 and 0.05 percent hydrogen sulfide by volume in Figure 14 do not follow the "inverse S" type shape, hinting that the concept of a "critical" chromium content may break down with mixtures low in hydrogen sulfide at high temperatures. Another exception is illustrated by the curves in Figure 12, which are noted to become progressively flatter with decreasing temperature.

18 Percent Cr–8 Percent Ni Stainless Steels

The chrome-nickel austenitic stainless steels including the widely used 18 Cr–8 Ni grade (Type 304) show consistently good performance in high temperature hydrogen sulfide bearing atmospheres. Inspection of the collected data reveals that on the average, 18 Cr–8 Ni steels can be expected to resist attack at least ten times more effectively than carbon or chrome-moly steels, especially in the higher ranges of hydrogen sulfide content. Backensto et al (A-29) report that no apparent difference in corrosion resistance was noted with stabilized grades (Types 321 and 347) or with the extra low carbon grade (Type 304 ELC) as compared to plain Type 304 steel. It should be remarked, however, that the Type 304 stainless steel used in these tests was presumably in the as-rolled condition and had not pre-

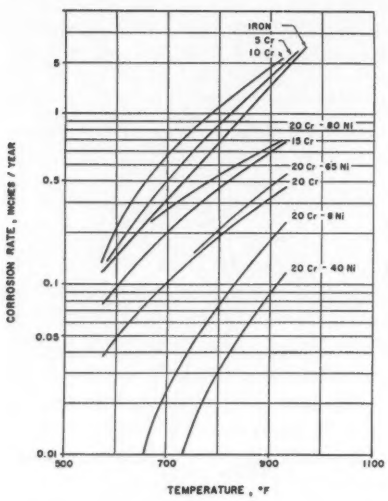

Figure 15—Effect of temperature on corrosion of Fe-Cr and Fe-Cr-Ni alloys by 16 percent hydrogen sulfide by volume in hydrogen-hydrogen sulfide mixture at 1100 psia pressure (A-64).

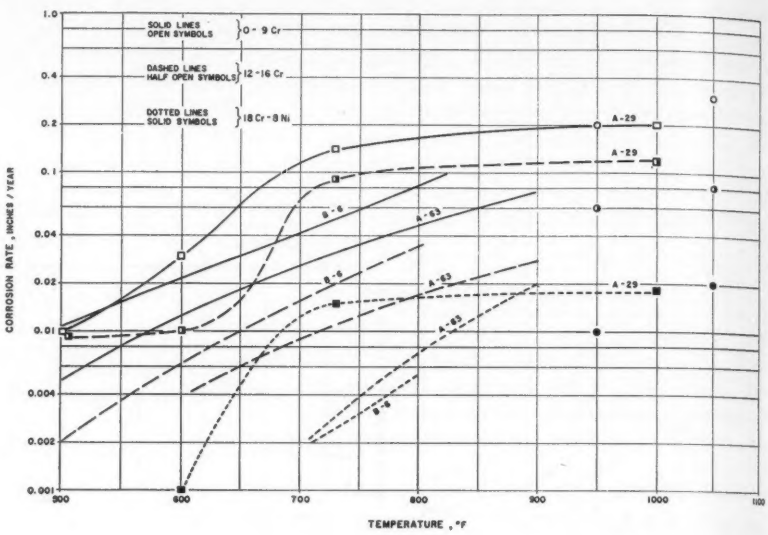
SOLID LINES OPEN SYMBOLS 0 - 9 Cr
DASHED LINES HALF OPEN SYMBOLS 12 - 16 Cr
DOTTED LINES SOLID SYMBOLS 18 Cr - 8 Ni
A-29
B-6
A-63
CORROSION RATE, INCHES / YEAR
TEMPERATURE, °F

Figure 16—Correlation chart showing corrosion of steels as a function of temperature at 3 psia hydrogen sulfide partial pressure.

viously been sensitized. Their results therefore do not conclusively prove that stabilization offers no apparent advantage in resisting high temperature hydrogen sulfide attack. Indeed, it may be argued that depletion of chromium from parts of the crystal (sensitization) may conceivably be detrimental in a medium where high chrome content is required for adequate resistance.

The 18 Cr–8 Ni grades of stainless steel have been shown to be more resistant to hydrogen sulfide corrosion than the equivalent nickel-free chrome steels (see Figures 11, 13 and 15) or even pure chromium (A-62, A-67). It is surprising that additions of nickel to chrome steel are effective in depressing corrosive attack because, as will be shown later, the presence of nickel in the absence of chromium decidely impairs the resistance of steels to hydrogen sulfide corrosion.

The 18 Cr–8 Ni types of stainless steel are considered by many as the optimum choice for equipment where alloy protection is required. Although they are not entirely free from attack, their resistance is sufficiently good to justify their use in even the most severely corrosive environments normally encountered in desulfurization units.

Nickel and Nickel Alloys

It is unanimously agreed that nickel and high nickel alloys are rapidly deteriorated in hydrogen sulfide containing atmospheres at elevated temperatures. The attack is in the form of severe intercrystalline sulfidation (A-10, A-19, A-57, A-62).

Straight nickel steels are attacked fairly rapidly. Dittrich (A-64) found that additions of nickel progressively decrease the resistance of laboratory Fe-Ni alloys under most conditions. Similarly, in his experiments with commercial alloys (A-63), he reports distinctly greater attack on 1 percent Ni steel as compared to plain carbon steel. In combination with chromium, additions of nickel are beneficial provided that the nickel is present in limited amounts. Dittrich (A-64) shows that nickel in excess of about 50-60 percent is detrimental regardless of the chromium content. This finding is confirmed by data of White and Marek (A-18) and McKay and Worthington (A-23), appearing in Tables 6 and 7 respectively; the alloys containing over 60 percent nickel with less than 20 percent Cr are seen to suffer accelerated attack.

Inspection of the data suggests that the Cr : Ni ratio might be a better criterion than the absolute nickel content for predicting the corrosion resistance of chrome-nickel steels. It appears that corrosion resistance is maintained provided that the Cr : Ni ratio does not fall below about 0.5, as supported by the data of Hafsten (A-19) and Dittrich (A-64). Raising the Cr : Ni ratio is beneficial only up to a certain point; very high ratios again tend to diminish corrosion resistance. This can be deduced from the rela-

TABLE 3—Code to Figure 16 Symbols

SYMBOL	MATERIAL	SOURCE	REFERENCE
———	0-6 Cr	Laboratory	A-63*
———	0-7.5 Cr	Laboratory	B-6
— — —	13 Cr	Laboratory	A-63*
— — —	13 Cr	Laboratory	B-6
- - - - - -	18 Cr - 8 Ni	Laboratory	A-63*
- - - - - -	18 Cr - 8 Ni	Laboratory	B-6 *
—□—	0-9 Cr	Laboratory	A-29
— -□- —	12-16 Cr	Laboratory	A-29
---■---	18 Cr - 8 Ni	Laboratory	A-29
○	5 Cr	Equipment	B-17
◐	12 Cr	Field Test	B-17
●	18 Cr - 8 Ni	Field Test	B-17

* The corrosion rates plotted in Figure16 are 50% of the experimental values; these adjustment were made to compensate for prolonged exposures.

tive inferiority of the straight chrome steels (infinite Cr:Ni ratio) as compared to the 18 Cr-8 Ni grades of stainless steels.

Aluminum and Aluminum Alloys

Aluminum has been found to be almost entirely resistant to high temperature attack at all concentrations and pressures of hydrogen sulfide (A-18, A-31, A-63). The poor mechanical properties of aluminum unfortunately preclude its use for pressure parts in high temperature equipment. In order to overcome this serious shortcoming and still take advantage of the excellent corrosion resistance offered by aluminum, the material may be employed either as an alloying constituent or in the form of surface coatings.

A series of laboratory investigations to study the behavior of experimental aluminum alloys has been conducted (A-53, A-62, A-65); the results are summarized in Tables 14, 15 and 18, respectively. These investigations indicate that aluminum additions to iron are effective provided they exceed a certain minimum amount. Fe-Al alloys containing less than about 5 percent Al may actually be less resistant than pure iron. It is interesting to recall that a similar trend was discovered with Fe-Cr alloys and it appears therefore that alloying additions of either chromium or aluminum are detrimental in small quantities but progressively more effective once a critical amount is exceeded.

Although the aluminum-rich Fe-Al alloys are excellent for resisting hydrogen sulfide attack, their commercial utilization is not feasible at present because the ordinary cast alloys are exceedingly hard and brittle.[7] The good corrosion resistance of Fe-Al compounds is however of practical significance because the majority of commercial aluminum coatings consist at least partially of diffused Fe-Al layers.

Aluminum Coatings

Aluminum surface coatings may be applied to ferrous base metals by a large variety of processes. The three major commercial processes are as follows:[8]

1. **Sprayed Coatings** (Metallizing)—Spray coatings can be built up to appreciable thicknesses and usually consist of pure aluminum. Adhesion to the steel is achieved by mechanical bonding, unless the coating is subjected to a diffusion heat treatment.
2. **Dipped Coatings** (Dip Aluminizing)—Hot dip aluminizing limits the coating thickness to a maximum of about 5-7 mils, of which only about one third remains as pure aluminum. The inner zone and the bonding layer consist of diffused Fe-Al alloys.
3. **Diffused Coatings** ("Calorizing")—The calorizing process produces a totally diffused coating such that not even the external portion contains any pure aluminum. The maximum practical thickness of calorizing is about 15-20 mils, inasmuch as thicker coatings require an excessively long diffusion heat treatment.

Experimental evidence from short time tests indicates that aluminum surface protection offers more resistance to hydrogen sulfide attack than solid stainless steel. The results from Kremer and Volk (A-46) as reproduced in Table 12 show both aluminized and calorized carbon steel to be more than one hundred times as resistant as 18 Cr-8 Ni steel to pure hydrogen sulfide at 1110 F. Vero (A-3) reports that alitizing (a diffusion coating similar to calorizing) is about 25 times as resistant as chrome steels. Laboratory data developed by several companies (A-8, A-29, B-3, B-9) also show aluminum protection to be effective.

All investigators agree that any aluminum coating must be maintained as an adherent and continuous layer in order to be effective. Experimentally produced breaks in calorizing have been shown to lead to failure of the coating (A-29). Good adhesion is perhaps even more important than the absence of pin-holes. British Petroleum (B-9) reported extensive pilot plant failures of calorizing in the form of peeling and flaking, which they attributed to faulty techniques of application. This obstacle can be overcome by observing proper techniques in preparing the surface and in applying the coating.

With respect to the comparative resistance of the various types of aluminum coatings in protecting steels from hydrogen sulfide attack, the spray type coatings without post diffusion treatment are considered to be the least satisfactory. This has been verified experimentally (B-9), and is attributed to the generally more porous and less adherent nature of spray metallized coatings. As to the merits of dip aluminizing and calorizing, arguments in favor of both methods can be presented. Thus it may be reasoned that dipping is superior because the pure aluminum overlay characteristic of dipped coatings is inherently more resistant to sulfide corrosion than the Fe-Al surface layer produced in calorizing.

In favor of calorizing, one might mention the appreciably thicker coating produced by diffusion techniques. Greater coating thickness is considered to be an advantage in that aluminum is gradually depleted from the surface by corrosion or erosion and by diffusion (into the steel).

The evidence gathered from laboratory investigations appears to favor calorizing (A-29, A-46). In the Socony Laboratories (A-29), exposure for 33 days to a hydrogen-hydrogen sulfide mixture at 500 psig and 1000 F did not bring on any discernible deterioration of calorizing while causing serious damage to the dip aluminized coating. Refinery experience on the other hand does not reflect the poor showing made by dip aluminizing in these laboratory tests; aluminized steel equipment in catalytic reforming service was recently found to be in generally excellent condition after several thousand hours of operation (B-1).

In evaluating the relative overall suitability of the three commercial methods of providing aluminum protection, consideration must be given not only to coating characteristics such as thickness, aluminum content, adhesion, porosity, etc. but also to the physical limitations of the equipment available for performing

(7) Recent developments in metallurgy show promise that Fe-Al alloys up to about 12 percent Al can be produced with acceptable ductility by vacuum melting techniques (A-25).

(8) A new type of aluminum coating has been developed by the Solar Aircraft Company and is currently in the experimental stage of use. Although this process appears promising, there is as yet insufficient experience for its proper evaluation, and therefore it is not included in the present discussion of aluminum coatings.

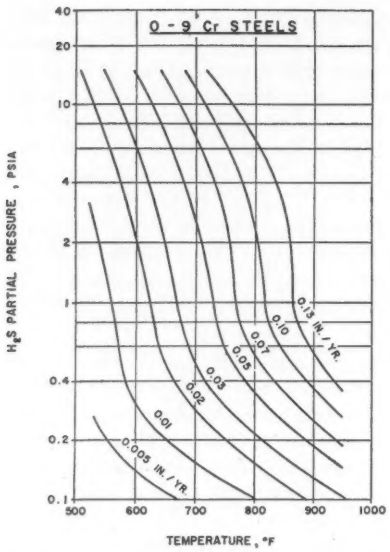

Figure 17—Design chart showing iso-corrosion curves as functions of temperature and hydrogen sulfide partial pressure for carbon and low chrome steels.

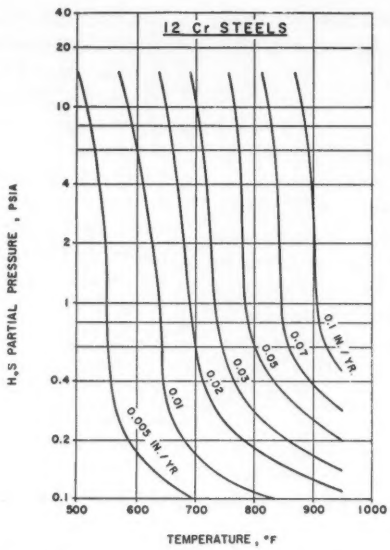

Figure 18—Design chart showing iso-corrosion curves as functions of temperature and hydrogen sulfide partial pressure for 12 Cr steels.

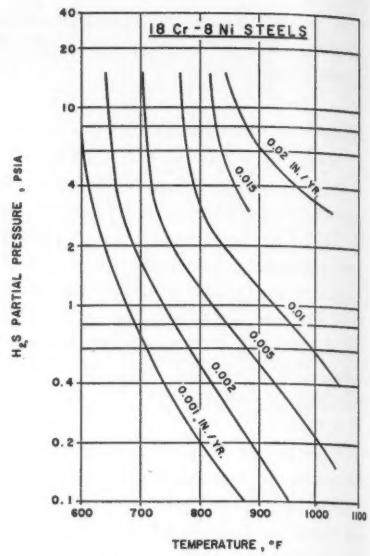

Figure 19—Design chart showing iso-corrosion curves as functions of temperature and hydrogen sulfide partial pressure for 18 Cr-8 Ni stainless steel.

the coating operation. At present, at least two oil companies are going ahead with plans to aluminize the high temperature equipment of existing and new catalytic reforming units; dipping, calorizing and spraying (with post diffusion treatment) are being used. Other refiners still consider stainless construction a more satisfactory and reliable means of providing corrosion resistance to these environments. It would be premature at this time to pass final judgment on the efficacy of aluminum coatings in catalytic reforming and desulfurizing service. Although the limited experience gained to date is encouraging, a more conclusive evaluation will have to be deferred until longer time service experience becomes available.

Miscellaneous Alloying Additions to Steel

In concluding this discussion of the behavior of materials in hydrogen sulfide atmospheres at elevated temperatures, some of the less common metals deserve brief mention. Since they are not ordinarily used in the pure form, they are of interest only as alloying additions to steel. Based on the scant data available, the directional effect on the corrosion rate falls into two categories. Molybdenum and manganese additions in small quantities are mildly detrimental (A-8, A-63, A-65); conversely, small amounts of silicon or tungsten appear to improve the resistance of steels to a limited extent (A-8, A-53, A-62, A-65). In connection with silicon, it is of interest to note that silicon diffusion coatings consistently outperformed aluminum diffusion coatings in a series of high temperature hydrogen sulfide corrosion tests (A-57).

Correlation of Corrosion Data

In order to compare the findings of the various investigators and thereby discover significant trends, the collected data are plotted in three correlation charts, Figures 2, 7 and 16. Figure 7 shows the corrosion rate at elevated temperatures and pressures as a function of hydrogen sulfide partial pressure. The conditions correspond to those found in the high temperature sections of catalytic reforming units. Figures 2 and 16 are plots of corrosion rate versus temperature at constant hydrogen sulfide partial pressures of 3.0 and 15.0 psia, respectively. These magnitudes of hydrogen sulfide concentrations are representative of the more severely corrosive atmospheres encountered in desulfurization units. Although the scatter of individual data points in all three correlations is fairly wide, this fact does not hide or invalidate the general trends which are revealed.

To present the correlations in a more comprehensive and practical form, the collected data have been condensed into three design charts, Figures 17, 18 and 19, respectively for low, intermediate and high alloy steels. In these charts, lines of equal corrosion resistance (iso-corrosion curves) have been plotted in terms of temperature and hydrogen sulfide partial pressure, considered to be the two most significant environmental corrosion variables. It is to be emphasized that the correlations presented in Figures 17, 18 and 19 are only approximate and therefore unsuitable for predicting corrosion rates accurately. In fact, the wide scatter of individual data points evident from Figures 2, 7 and 16, indicates that the families of iso-corrosion curves would be more correctly represented by wide, overlapping bands instead of individual lines; this was not done for the sake of preserving clarity.

It is difficult to estimate the accuracy of the various correlations because the accuracy of the com-

ponent corrosion data cannot be readily evaluated. With specific reference to the design charts, this estimate is further complicated by the fact that in the process of constructing the iso-corrosion curves, personal judgment was used in averaging, weighing and extrapolating the data.

In general, it can be assumed that the design correlations are most accurate and reliable in the range of low hydrogen sulfide partial pressures and high temperatures (characteristics of catalytic reforming service) because of the greater wealth of available data at these conditions. Probably the least reliable portions of the design charts cover the area of intermediate partial pressures (i.e., from about 3-10 psia) where comparatively few experimental data and practically no service results have been obtained. Of the three design charts, Figure 18 (11-13 Cr steels) is considered to be less reliable than either Figures 17 or 19. This is attributed partially to the greater paucity of corrosion data on 12 Cr steels, but principally to the widely fluctuating behavior of these borderline materials.

The sources of error in the collected data are of diverse origin. Empirical data obtained from inspections of refinery equipment are of doubtful validity because the corrosion rates so determined frequently are based on assumed rather than measured original thicknesses. Estimates of corrosion rates based on scale build-up are even more unreliable because they presuppose that the scale has remained intact and furthermore that its volume ratio is known. Perhaps an even more serious source of error in field derived corrosion measurements is the difficulty of estimating environmental conditions which can be considered representative for the entire operating run. This problem is magnified with respect to hydrogen sulfide concentrations because refineries do not ordinarily record hydrogen sulfide contents as routine operating data.

The sources of error discussed above do not pertain to experimental data developed in the laboratory, where the test conditions are carefully controlled. Data of this type also have limitations which may seriously restrict their significance in correlations. Foremost among these limitations is the short time testing period necessary in laboratory test programs, which consequently yield exaggerated values of corrosion rate. Attention is further called to the fact that the conditions at which many of the laboratory studies quoted have been conducted, differ widely not only from one another but also from the conditions normally present in catalytic or desulfurizing units.

The foregoing discussion of error has been included to remind the reader of the approximate nature of the correlations shown in the design charts, and of their consequent limitations. As their name implies, these charts are intended primarily as design tools for specifying reasonable corrosion allowances and minimum alloy requirements. It is estimated that on the average, the predicted rates are correct within a factor of 2, but even this limited accuracy should not be relied upon for all situations.

General Summary

Nature of Sulfide Scale

The layers of sulfide scale formed on steels are characterized as flaky, brittle, porous and generally non-adherent. Because of its semi-pervious nature the scale, even when intact, does not appreciably retard further corrosion. The scale's tendency to flake off and plug equipment has been the frequent cause for serious operational difficulties in catalytic reforming and desulfurizing units. The principal reactions governing the rate of scale formation appear to be diffusion processes.

Principal Environmental Factors Affecting Corrosion

The principal variables affecting corrosion in hot hydrogen sulfide bearing atmospheres are temperature and hydrogen sulfide content. In the range of conditions ordinarily encountered in catalytic reforming and desulfurizing service, the best correlating variable between corrosion rates and hydrogen sulfide content appears to be the partial pressure of hydrogen sulfide. Duration of exposure is an important factor only in the initial stages of exposure when the rates are very high. After about one week's time, the corrosion rate remains essentially constant.

Exposure to conditions of intermittent heating and cooling, or alternating reducing and oxidizing atmospheres is considered detrimental, inasmuch as these cyclic effects contribute to the more rapid deterioration of the semi-protective sulfide scale.

Relative Suitability of Constructional Materials

Carbon steel and the chrome-moly alloy steels are attacked with equal severity by gas mixtures containing hydrogen sulfide as the principal corrodent. The 12 Cr steels offer moderately higher resistance than the lower alloy materials, but the degree of improvement is erratic and unpredictable. The stainless steels, notably the chrome-nickel grades, are considered to possess excellent resistance. Although they are not entirely free from hydrogen sulfide attack, they stand up well consistently in even the more severely corrosive environments normally encountered.

Aluminum, iron-aluminum alloys and a variety of aluminum-rich surface coatings show negligible corrosion rates in hot gas mixtures containing hydrogen sulfide. The aluminum coating is considered to afford excellent protection to the underlying steel, provided that the coating is maintained as an adherent and impervious layer.

Materials for Catalytic Reforming and Desulfurizing Equipment

The quantities of hydrogen sulfide present in the majority of desulfurization units are sufficiently high (approximately 5 percent) to cause severe scaling of carbon and low alloy steels at reactor temperatures. In locations where alloy protection is required, the 18 Cr–8 Ni stainless steels are generally considered as the optimum choice of material.

The quantities of hydrogen sulfide present in cata-

lytic reforming units are usually of such low order that carbon or low alloy steels are adequately resistant (in practice, carbon-moly or chrome-moly steels are used for resistance to hydrogen embrittlement). In some instances, particularly where no provisions have been made for pre-desulfurizing the feed or for scrubbing the recycle gas, some measure of corrosion protection is required. As in the case of desulfurization service, the use of 18 Cr–8 Ni steels is favored in view of the inconsistent performance of the 12 Cr steels.

Aluminum coatings applied to carbon or alloy steels by spraying, dipping or diffusion processes have provided effective corrosion protection in a number of recent installations, and show promise as a suitable alternate for stainless steel construction. However, the experience with these coatings in reformer and desulfurizer equipment is as yet too limited to assess their effectiveness or relative reliability for prolonged service.

In conclusion, it should be noted that corrosion resistance alone is seldom the sole criterion for chosing a satisfactory material. Aside from the obvious considerations of strength and cost, such factors as ease of fabrication and the structural stability at high temperatures help to shape the final choice of material.

Acknowledgment

The authors express their indebtedness to the various oil companies for permitting the release of hitherto unpublished data. Special thanks are tended to the Atlantic Refining Company and the British Petroleum Company for their generous contribution of results obtained from extensive laboratory and pilot plant studies. The authors also acknowledge the cooperation of their colleagues in the M. W. Kellogg Company.

APPENDIX 1

Abstracts Of Published Corrosion Data (Reference Series "A")

Ref. A-8 Application of Calorized Refinery Pipe Still Tubes. C. L. CLARK, R. S. BROWN AND A. E. WHITE. *Oil and Gas Journal*, **33**, 44 (1935) Mar. 28

The results of several 24 hour laboratory corrosion tests conducted at atmospheric pressure are summarized in Table 4. Rates are in inches per year.

TABLE 4

MATERIAL	6% H_2S at 900 F		100% H_2S at 1200 F	
	Bare	Calorized	Bare	Calorized
Carbon steel	0.188	0.0064	13.00	0.158
0.05 Mo	0.324	0.0061	15.40	0.178
5 Cr	0.063	0.0037	7.26	0.117
5 Cr—½ Mo	0.122	0.0220	6.73	0.146
5 Cr—1 W	0.105	.....	3.22	0.274
18 Cr—8 Ni	0.066	0.0066	0.20	0.117

Ref. A-13 Corrosion Data Survey (1954 Edition). G. A. NELSON, Shell Development Company.

The data in Table 5 are corrosion rates in 100 percent hydrogen sulfide at 1.0 atmosphere (taken from page H-2).

TABLE 5

Temperature (Degrees F)	CORROSION RATE (Ipy)		
	500	600	700
Carbon steel	<0.02	.....	>0.05
12 Cr	.....	<0.02	0.02—0.05
18 Cr—8 Ni	.....	.....	<0.02
Aluminum	.....	<0.02	.....

Ref. A-18 Corrosion of Mild Steel and Alloys by Hydrogen Sulfide at 500 C and Atmospheric Pressure. A. WHITE AND L. F. MAREK. *Ind. Eng. Chem.*, **25**, No. 8, 859-861, (1932) Aug.

Table 6 below summarizes results of laboratory corrosion tests in moist hydrogen sulfide at 932 F and 1.0 atmosphere pressure. The test period was approximately four weeks.

TABLE 6

MATERIAL	Corrosion Rate (Ipy)
Carbon steel	0.36
1 Cr	0.28
13 Cr	0.11
18 Cr—8 Ni	0.026
12 Cr—63 Ni	0.43
Aluminum	Nil

Ref. A-23 Corrosion Resistance of Metals and Alloys. R. J. MCKAY AND R. WORTHINGTON. Reinhold Publishing Corp. (1936).

Page 324 . . . Corrosion rates reproduced in Table 7 below are based on data by W. Scholl, which appeared originally in the *Trans. Electrochem. Soc.*, **50**, 47-89 (1926). The rates were reported as weight gain in mg per sq dm per day (mdd). These data are also reproduced in the Corrosion Handbook (A-14), page 651.

The test pieces were exposed 28.5 hours at 900 F to hydrogen sulfide, presumably at 1.0 atmosphere.

TABLE 7

MATERIAL	Corrosion Rate (Ipy)
Carbon steel	0.93
8 Cr	0.82
14 Cr	0.52
19 Cr	0.15
25 Cr	0.15
26 Cr—21 Ni	0.15
17 Cr—25 Ni	0.15
18 Cr—75 Ni	1.9

Ref. A-29 High Temperature Hydrogen Sulfide Corrosion. E. B. BACKENSTO, R. E. DREW AND C. C. STAPLEFORD. *Corrosion*, **12**, No. 1, 22-31 (1956) Jan.

An extensive laboratory corrosion investigation was conducted to study high temperature hydrogen sulfide attack on commercial steels. The series of experiments consisted of more than 80 runs, each including 15-25 different test coupons. The range of conditions studied were 0.002-1.0 mol percent hydrogen sulfide, 500-1300 F, and 0-500 psig hydrogen pressure. The coupons were exposed up to 800 hours duration (majority 150-200 hours), and were evaluated on a weight loss basis.

The principal results are summarized graphically in Figures 3, 8, 9, 10, and 14.

In addition to the laboratory coupon tests in hydrogen-hydrogen sulfide atmospheres, a number of three week runs were made to simulate naphtha furnace conditions by pumping a mixture of Kuwait naphtha vapor, 0.085 mol percent hydrogen sulfide and 11.1 mol percent H_2, through a 5 percent chrome tube in a gas-fired furnace. The furnace outlet conditions were 826 F and 460 psig. Table 8 lists the corrosion rates obtained from several sections of the 5 Cr furnace tube.

In addition to bare steels, calorized, hot dipped and

spray metallized aluminum coatings were tested at various conditions. Calorizing appears to be the most effective type of aluminum coating investigated. It is emphasized that a continuous coating must be maintained in order to remain effective.

TABLE 8

Average Temperature (Degrees F)		H_2S Partial Pressure (Psia)	Corrosion Rate (Ipy)
Naphtha	Tube Skin		
645	876	0.40	0.035
711	859	0.40	0.026
770	905	0.40	0.044

Ref. A-31 Hydrogen Sulfide Corrosion at High Temperatures. P. F. MIKHALEV AND S. I. VOL'FSON. *Neftyanoe Khozyaistvo,* **19,** No. 7, 26-30, (1938) July.

Corrosion tests were made in pure hydrogen sulfide at 1.0 atmosphere, with exposures ranging up to 150 hours. Table 9 summarizes the results reported originally in weight loss per unit area.

In the English abstract of the Russian paper (CA 33/9240-8), it is incorrectly stated that 5 Cr steel is superior to 13 Cr steel. In the original text, the authors conclude that 13 Cr steel is more resistant than 5 Cr steel.

TABLE 9

Temperature	CORROSION RATE (Ipy)			
	482 F		932 F	
	Dry	Moist	Dry	Moist
Carbon steel	0.022	0.030	0.28	0.53
13 Cr	Nil	0.024	0.09	0.23
19 Cr—6 Ni	0.006	0.008	0.003	0.004
26 Ni	0.017	0.035	0.34	0.52
Aluminum	Nil	Negl.	Nil	Nil

Ref. A-35 Korrosionsbestaendigkeit Von Chrom-Nickel-Eisen Legierungen. E. WELLMANN. *Zeitschrift fuer Elektrochemie,* **37,** No. 3, 142-156 (1931).

Table 10 summarizes the results of several four hour laboratory corrosion tests conducted in 100 percent hydrogen sulfide at atmospheric pressure. The rates were reported originally as loss of weight in mg per sq cm.

TABLE 10

Temperature	CORROSION RATE (Ipy)				
	572 F	662 F	700 F	752 F	1020 F
13 Cr	....	....	0.26	....	0.77
18 Cr—8 Ni	0.022	0.066	0.088	0.11	0.37

Ref. A-40 Metallurgical Methods for Combating Corrosion and Abrasion in the Petroleum Industry. B. B. MORTON. *J. Inst. Petr.* (British), **34,** No. 289 (1948) Jan.

Page 51 . . . Table 11 reproduced on this page is an extract from a graph[9] showing relative corrosion of chrome steels as a function of chromium content in an atmosphere of pure hydrogen sulfide (presumably at 1.0 atmosphere), at 850 F, after 168 hours exposure.

(9) This graph also appears in the Corrosion Handbook (A-14) page 655; it should be noted, however, that it is not correctly reproduced there.

TABLE 11

Percent Cr in Alloy	Penetration (Percent of Carbon Steel)	
0	....	(100%)[1]
3	100	(67%)
5	72	(56%)
9	40	(38%)
12	26	(27%)
18	12	
26	7	

[1] The numbers in parentheses are taken from a slightly different reproduction of apparently the same experimental data (A-47). Both versions of this graph are prevalent in the literature.

Ref. A-46 Production and Use of Heat Resisting Aluminum Coatings. G. KREMER AND K. E. VOLK. *Stahl und Eisen,* **66-67,** 250-255 (1947)

Table 12 summarizes the results of corrosion tests in pure hydrogen sulfide, presumably at 1.0 atmosphere. The length of exposure was 50 hours, with results reported originally as weight loss in gr per hour per square meter.

TABLE 12

TEMPERATURE	CORROSION (Ipy)	
	930 F	1110 F
Carbon steel	0.83	....
18 Cr—8 Ni	0.29	0.79
Aluminized C. S.	....	0.0009
Calorized C. S.	....	0.003

Ref. A-53 Staehle Fuer Triebstoffgewinnungsanlagen. F. K. NAUMANN. *Chemische Fabrik,* **11,** No. 31/32, 365-376 (1938) Aug. 3

The corrosion rates reproduced in Table 13 are transcribed from graph[10] showing weight loss in grams per square meter per hour versus percent Cr in steel, obtained from 120 hour tests with 100 percent hydrogen sulfide at atmospheric pressure.

The corrosion rates reproduced in Table 14 are the results of experiments with Fe-Al alloys exposed for 50 hours to hydrogen sulfide at atmospheric pressure.

TABLE 13

TEMPERATURE	Corrosion Rate (Ipy)	
	752 F	932 F
Carbon steel	0.26	1.1
5 Cr	0.24	1.0
9 Cr	0.20	0.7
12 Cr	0.13	0.4
17 Cr	0.09	0.2
25 Cr	....	0.1
18 Cr—9 Ni	0.08	0.2
21 Cr—78 Ni	0.07	....
26 Cr—20 Ni	0.06	0.1

TABLE 14

Percent Al in Fe—Al Alloy	Weight Loss (Grams/Hour/Square Meter)		
Temperature	842 F	932 F	1112 F
0.0 percent	11	18	57
1.0 percent	14	41	142
1.5 percent	17	57	192
2.0 percent	13	44	162
3.0 percent	10	20	135
4.0 percent	8	11	37
5.0 percent	6	7	23
6.7 percent	4	5	12
7.0 percent	2	3	7

(10) The graph also appears in Corrosion Handbook (A-14) page 652, but it should be noted that the values given there are too small by a factor of 10,000. A correct reproduction of the graph can be found in Reference A-43.

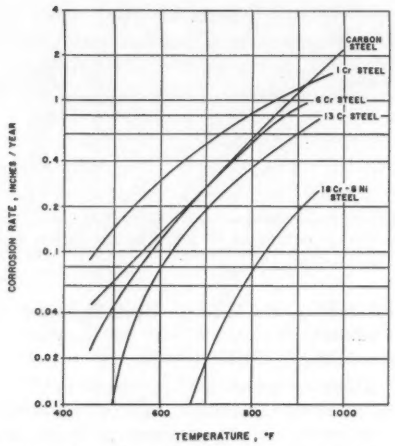

Figure 20—Effect of temperature on corrosion of steels by 16 percent hydrogen sulfide by volume in hydrogen-hydrogen sulfide mixture at 1100 psia pressure (A-63).

Ref. A-62 Ueber Das Verhalten Hitzbestaendiger Legierungen Gegen Schwefel. H. GRUBER. *Zeitschrift fuer Metallkunde,* **23,** No. 5, 151-157 (1931)

A series of one hour laboratory tests in pure hydrogen sulfide at 1292-1830 F and 1.0 atmosphere were conducted with 29 different alloys. The results are summarized in Table 15, showing the effect of various alloying ingredients for the lowest temperature condition investigated.

TABLE 15

Alloy No.	Composition of Alloy (%)								Increase in Weight at 1292 F (Mg./Hr./57.6 sq cm)[1]
	Fe	Ni	Cr	Mn	Al	Co	Mo	W	
1	100	..	..	..	..	..	..	..	760
2	75	..	25	..	..	..	..	..	580
3	..	100	..	..	..	..	..	..	9700
4	50	25	25	..	..	..	..	..	430
5	24	61	15	..	..	..	..	..	970
6	20	61	15	4	..	..	..	..	500
7	20	61	15	4	5	..	..	..	310
8	20	61	15	4	10	..	..	..	130
13	20	61	15	4	15	..	..	..	190
14	..	95	..	..	5	..	..	..	4400
9	..	90	..	..	10	..	..	..	290
15	..	85	..	..	15	..	..	..	40
16	95	..	..	..	5	..	..	..	1370
10	90	..	..	..	10	..	..	..	330
17	85	..	..	..	15	..	..	..	50
11	75	..	25	..	10	..	..	..	160
12	..	..	100	..	..	..	..	..	640
18	..	..	90	..	10	..	..	..	280
19	..	..	..	..	..	100	..	..	3700
20	..	..	..	..	5	95	..	..	3200
21	..	..	..	..	10	90	..	..	10
22	..	..	..	..	15	85	..	..	10
23	15	61	15	2	..	..	7	..	1240
24	..	..	..	..	..	..	100	..	30
25	..	90	..	..	..	..	10	..	7600
26	..	80	..	..	..	..	20	..	6000
27	..	70	..	..	..	..	30	..	6400
28	..	55	15	..	..	..	30	..	17300
29	..	50	..	..	..	..	..	50	1340

[1] For ferrous alloys, the rates can be approximately converted to inches per year by multiplying by a factor of 0.013.

Ref. A-63 Ueber Den Einfluss Des Druckes Beim Angriff Von Schwefelwasserstoff Auf Staehle. E. DITTRICH. *Chemische Fabrik,* **6,** No. 2, 25-30 (1933) Jan. 11

Laboratory tests were conducted to study quantitatively the extent of corrosion on a number of commercial steels in hydrogen-hydrogen sulfide mixtures. The variables investigated were temperature, total pressure, hydrogen sulfide concentration, hydrogen sulfide partial pressure, and length of exposure.

Figures 4, 5, 6 and 20 summarize the more important findings, reported originally on the basis of weight gain per unit area. The rates given in Table 16 below are derived from the curves in Figures 5, 6 and 20, and are for exposures of 20 hours. Dittrich showed that the rates after 50 hours are approximately half those obtained after 20 hours.

TABLE 16

Temperature (Degrees F)	H_2S Partial Pressure (Psia)	CORROSION RATE (Ipy)[1]			
		0—6 Cr	10 Cr[2]	13 Cr	18 Cr—8 Ni
500	3.0	0.010	....	0.001	<0.001
	15.0	0.030	....	0.005	<0.001
600	3.0	0.025	....	0.007	<0.001
	15.0	0.070	0.055	0.027	<0.001
700	3.0	0.050	....	0.017	0.004
	15.0	0.13	0.14	0.068	0.008
750	3.0	0.070	....	0.025	0.008
	15.0	0.18	0.22	0.093	0.017
800	3.0	0.09	....	0.033	0.015
	15.0	0.22	0.29	0.13	0.031
850	3.0	0.12	....	0.043	0.025
	15.0	0.27	0.39	0.16	0.050
900	3.0	0.15	....	0.056	0.040
	15.0	0.35	0.56	0.22	0.078

[1] The corrosion rates plotted in the correlation charts Figures 2 and 16 are half of those listed in Table 16; these adjustments were made as an attempt to compensate for prolonged exposures.
[2] The corrosion rates for the 10 Cr iron are derived from data presented in Part II of Dittrich's paper (A-64), summarized in Figure 15.

Ref. A-64 Ueber Den Einfluss Des Druckes Beim Angriff Von Schwefelwasserstoff Auf Staehle.—II. Chromeisen, Nickeleisen. E. DITTRICH. *Chemische Fabrik,* **10,** No. 13/14, 145-150 (1937) Mar. 31.

In Part II of this investigation, Dittrich repeated the experiments performed in Part I (Ref. A-63), using laboratory alloys containing iron, chromium and nickel in place of the previously used commercial steels, in order to study the specific influence of the alloying constituents on high temperature and pressure corrosion by hydrogen sulfide-hydrogen mixtures. Extracts from his results are reproduced in Figures 12 and 15.

Ref. A-65 Ueber Den Einfluss Schwefelwasserstoffhaltiger Gase Auf Eisen Und Auf Einige Eisenlegierungen. W. BAUKLOH AND E. SPETZLER. *Korrosion u. Metallschutz,* **16,** No. 4, 116-121 (1940)

A series of laboratory tests in hydrogen-hydrogen sulfide and nitrogen-hydrogen sulfide mixtures were conducted to evaluate the effect of temperature and diluent gas on the corrosion of iron and several iron alloys. The test pieces were exposed for seven hours to 2 percent hydrogen sulfide (1.0 atmosphere partial pressure) at temperatures ranging up to 1650 F; the extent of attack was evaluated by weight gain per unit area. The corrosion rates obtained with Fe-Cr and Fe-Al alloys are summarized in Tables 17 and 18 respectively.

TABLE 17

% Cr in Alloy	CORROSION RATE (Ipy)					
	752 F		932 F		1112 F	
Diluent Gas	H_2	N_2	H_2	N_2	H_2	N_2
0.0%	0.35	....	1.1	....	2.8	....
0.35%	....	....	0.9	0.5	3.2	2.8
12.9%	....	....	0.35	0.5	2.1	1.8
27.0%	....	....	0.35	0.3	1.4	1.1

TABLE 18

% Al in Alloy	CORROSION RATE (Ipy)					
	932 F		1112 F		1292 F	
Diluent Gas	H_2	N_2	H_2	N_2	H_2	N_2
0.0%	1.1	....	2.8	....	3.9	....
1.0%	0.70	0.26	2.6	1.1	4.6	2.1
6.7%	0.35	0.18	0.53	0.21	1.0	0.3

Ref. A-67 Verzunderung Von Metallen Durch Schwefel Und Schwefelhaltige Gase. O. KUBASCHEWSKY AND O. VON GOLDBECK. *Metalloberflaeche.* **8,** No. 3, 33-36 (1954) Mar.

Table 19 is an extract from a series which lists some of the more common metals arranged in order of increasing resistance to high temperature hydrogen sulfide attack.

TABLE 19

MATERIAL	Nearest Commercial Designation
Ni, Co	.... (Least resistant)
Fe	Carbon steel
7 Fe—77 Ni—14 Cr	Inconel
85 Fe—15 Cr	Type 430
75 Fe—25 Cr	Type 446
Cr	....
74 Fe—18 Cr—8 Ni	Type 304
Fe—12 Al	....
Ta,Mo,W	....
Al, Mg	.... (Most resistant)

Ref. A-68 Vom Werkstoff Zum Bauwerk. H. STAEGER. *Annales Suisses des Sciences Appliquees et de la Technique,* 6, No. 5, 121-146 (1940) May

H. Staeger summarizes some experimental results on high temperature hydrogen sulfide attack obtained by F. K. Naumann, which were published originally in the Krupp Technische Mitteilungen (1938). Table 20 contains the results of a series of laboratory corrosion tests, presumably in pure hydrogen sulfide at 1.0 atmosphere. The rates were originally reported as weight loss per unit area (grams/hour/square meter) for 50 hours exposure.

TABLE 20

	CORROSION RATE (Ipy)							
Temperature	600 F	700 F	750 F	800 F	850 F	900 F	950 F	1000 F
Carbon steel	0.09	0.16	0.26	0.52	0.67	0.90	1.1	1.4
18 Cr—8 Ni	....	....	0.009	0.013	0.022	0.035	0.049	0.075

APPENDIX 2

Abstracts of Unpublished Corrosion Data (Reference Series "B")

Ref. B-1 American Oil Company. Inspection of Ultraforming Unit at Texas City, Texas (July 1955).

(a) Corrosion Rates in Furnace tubes:
After 2131 hours operation, the tubes in the preheat, reheat and recycle gas furnaces were examined. Based on original caliper measurements these tubes showed the corrosion rates listed in Table 21.

(b) Condition of Aluminized Equipment:
The aluminized (dipped and sprayed) equipment was generally found to be in excellent condition. However, in some locations the outermost aluminum layer had completely diffused.

TABLE 21

Furnace	Section	Location	Estimated Skin Temp. (Degrees F)	H_2S Partial Pressure (Psia)	CORROSION RATE (Ipy)		
					Carbon Steel	1¼ Cr-½ Mo	2¼ Cr-1 Mo
B-1	Convection	Inside roll	600	0.05	0.021	....	....
B-1	Convection	Inside roll	600	0.05	0.015	....	....
B-1	Convection	Behind roll	600	0.05	0.013	....	....
B-1	Convection	Behind roll	600	0.05	0.006	....	....
B-1	Radiant	Inside roll	900	0.05	nil	....	0.017
B-1	Radiant	Behind roll	900	0.05	0.017	....	0.041
B-1	Radiant	Firebox	850	0.05	0.056	....	0.120
B-2	Radiant	Firebox	950	0.22	....	0.039	0.065
B-4	Radiant	Firebox	950	0.20	....	0.015	....
B-4	Radiant	Firebox	950	0.20	....	0.058	....
B-5	Radiant	Firebox	950	0.19	....	0.031	....
B-5	Radiant	Firebox	950	0.19	....	0.077	....
B-6	Radiant	Firebox	950	0.17	....	0.039	....
B-6	Radiant	Firebox	950	0.17	....	0.070	....
B-7	Radiant	Firebox	950	0.16	....	0.043	....
B-7	Radiant	Firebox	950	0.16	....	0.149	....

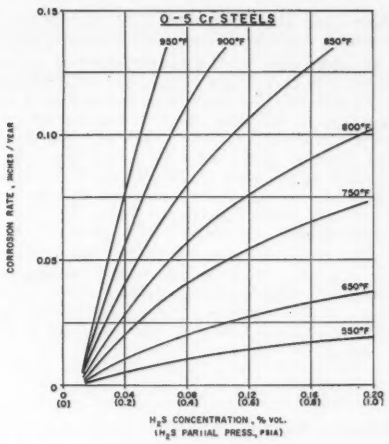

Figure 21—Effect of hydrogen sulfide content and temperature on corrosion of carbon and low chrome steels in hydrogen-rich catalytic reformer gases at 500 psig pressure (B-3).

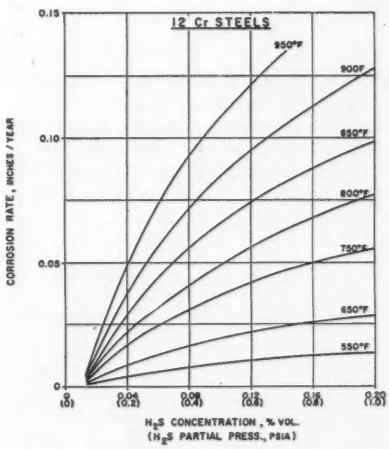

Figure 22—Effect of hydrogen sulfide content and temperature on corrosion of 12 Cr chrome steel in hydrogen-rich catalytic reformer gases at 500 psig pressure (B-3).

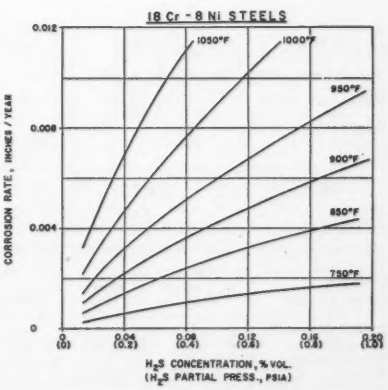

Figure 23—Effect of hydrogen sulfide content and temperature on corrosion of 18 Cr-8 Ni stainless steel in hydrogen-rich catalytic reformer gases at 500 psig pressure (B-3).

Ref. B-2 American Oil Company. Test Specimens in Ultraforming Unit at Texas City, Texas (July 1955).

Examination of several pre-stressed test pieces exposed for 2131 hours yielded the corrosion rates listed in Table 22. The specimens had not been individually weighed or calipered prior to installation because they were originally intended only to determine whether the process gases had a carburizing effect on the various alloy steels. Inasmuch as the original dimensions of the test pieces are not exactly known, the corrosion rates quoted in Table 22 are considered approximate.

The bolts and nuts (5 Cr-1/2 Mo and carbon steel respectively) used in the test assemblies gave the corrosion rates shown parenthesized in Table 22. The error limits indicated correspond to the variation in diameter as permitted by the respective ASTM specifications.

Ref. B-3 Atlantic Refining Company. Laboratory Corrosion Testing Program (1954-1955).

The results of a series of 24 hour laboratory corrosion tests are summarized in graphical form in Figures 13, 21, 22 and 23. The addition of H_2O or HCl vapors had little if any effect on the measured corrosion rates. Aluminum coated carbon steel performed about equally well as 18 Cr-8 Ni stainless steel.

Ref. B-4 Atlantic Refining Company. Inspection of Catforming Equipment.

The experimenters believe that the corrosion rates obtained experimentally (see Ref. B-3) are realistic inasmuch as they show good agreement with corrosion rates obtained on three operating Catforming Units (See Table 23).

Ref. B-5 British Petroleum Company Ltd. Corrosion Tests in Alternating Reaction-Regeneration Conditions (July 1949).

Corrosion tests in a laboratory scale Autofiner reactor were conducted to determine the effect of regeneration on the extent of corrosion, and also to investigate the effect of mill scale. A total of six samples were exposed to the following environments: Samples 1 and 2 were exposed to two successive reaction periods with intermittent cooling, samples 3 and 4 to two successive regeneration periods with intermittent cooling, and samples 5 and 6 to a complete reaction-regeneration-reaction cycle. The measured corrosion rates are summarized in Table 24. The presence of mill scale was found to have little effect on subsequent corrosion by the process gases.

Ref. B-6 British Petroleum Company Ltd. Laboratory Corrosion Testing Program (Dec. 1949).

Laboratory corrosion tests of 48 hours duration were conducted in hydrogen-hydrogen sulfide mixture at atmospheric pressure, and an average hydrogen sulfide partial pressure of about 6.0 psia. Figure 11 shows the resultant correlation of corrosion rate as function of temperature for several ferrous materials. At different hydrogen sulfide contents, the corrosion rate (R) varies with the hydrogen sulfide partial pressure (P) according to the following approximate relationship, valid up to 180 psia hydrogen sulfide partial pressure:

$$\frac{R_1}{R_2} = \left(\frac{P_1}{P_2}\right)^{0.4}$$

This formula was used in conjunction with Figure 11 to to obtain the values listed in Table 25.

The experimenters found that for long exposure time, there is evidence of significant decrease in corrosion rate. This effect is small in carbon and chrome steels but considerable in 18 Cr-8 Ni stainless steel. Moisture tends to increase the rate to a limited extent, whereas the presence of hydrocarbon vapors has no detectible effect.

Ref. B-7 British Petroleum Company Ltd. Inspection of Autofining Pilot Plant at Grangemouth, Scotland (Feb. 1950).

Table 26 lists the corrosion rates measured on carbon steel equipment operating in an atmosphere of approximately 780 F and 15 psia hydrogen sulfide partial pressure.

TABLE 22

Location	CORROSION RATE (Ipy) B-2 Inlet	B-2 Outlet	D-2 Inlet	D-6 Outlet	Aver. of Columns 2,3,4.
Temperature	726F	1025F	950F	950F	950—1025F
H_2S Part. Press.	0.22 Psia	0.20 Psia	0.19 Psia	0.14 Psia	0.14—0.20 Psia
Carbon steel	0.006	0.050	0.046	0.062	0.053 (0.058 ±0.018)
1¼ Cr—½ Mo	0.010	0.064	0.040	0.060	0.055
2¼ Cr—1 Mo	0.008	0.072	0.030	0.062	0.055
5 Cr—½ Mo	0.006	0.076	0.092	0.058	0.075 (0.044 ±0.012)
9 Cr—1 Mo	0.006	0.096	0.036	0.040	0.057
12 Cr	0.002	0.028	0.000	0.062	0.030
18 Cr—8 Ni	0.010	0.020	0.010	0.008	0.013

TABLE 23

LOCATION	Material	H_2S Content % Volume	H_2S Partial Press. (Psia)	CORROSION RATES (Ipy) Catformer	Laboratory
Port Arthur, Texas	2¼ Cr—1 Mo	0.032—0.040	0.16—0.20	0.035—0.040	0.040—0.054
Tulsa, Oklahoma[1]	5 Cr—½ Mo	0.016—0.048	0.08—0.24	0.035—0.045	0.012—0.069
Philadelphia, Pennsylvania	12 Cr	0.012—0.020	0.06—0.10	0.006—0.008	0.002—0.011

[1] See D-X Sunray Oil Company (B-10)

TABLE 24

OPERATION	Max. Temp. (Deg. F)	Press. (Psig)	GAS COMP. (Mol %) H_2S	SO_2	SO_3	Time (Hrs.)	CORROSION RATE (Ipy) 1	2	3	4	5	6
Reaction	782	115	6.7	0	0	131	0.133	0.169	*	*	....	....
Regen'n	1145	Atmos.	0.3	0.03	0.03	24	*	*	—.023	—.023	....	....
Reaction	782	117	5.9	0	0	126	0.155	0.175	*	*	....	....
Regen'n	1090	Atmos.	0.3	0.03	0.03	24	*	*	nil	nil	*	*
Corrosion rates based on exposure to reaction gases (257 hrs.)							0.144	0.172	.....		0.173	0.159
							0.158 avg.		.....		0.167 avg.	

* Not exposed.

TABLE 25

Temperature (Degrees F)	H_2S Partial Press. (Psia)	CORROSION RATE (Ipy) 0—7.5 Cr	13 Cr	18 Cr—8 Ni[1]
500	3.0	0.0088—0.0136	0.0013—0.0042	0.001
	6.0	0.011 —0.017	0.0018—0.0052	0.001
	15.0	0.017 —0.026	0.0027—0.0078	0.001
600	3.0	0.018 —0.027	0.0038—0.0096	0.0013
	6.0	0.023 —0.034	0.0048—0.012	0.0018
	15.0	0.034 —0.051	0.0072—0.018	0.0027
700	3.0	0.035 —0.050	0.011 —0.022	0.0038
	6.0	0.044 —0.063	0.014 —0.027	0.0048
	15.0	0.066 —0.094	0.021 —0.040	0.0072
750	3.0	0.049 —0.070	0.018 —0.034	0.0064
	6.0	0.061 —0.088	0.022 —0.042	0.0080
	15.0	0.091 —0.13	0.033 —0.063	0.012
800	3.0	0.070 —0.10	0.030 —0.050	0.011
	6.0	0.088 —0.13	0.038 —0.063	0.014
	15.0	0.13 —0.19	0.057 —0.094	0.021

[1] The corrosion rates plotted in the correlation charts (Figures 2 and 16) are half of those listed in Table 25; these adjustments were made as an attempt to compensate for prolonged exposures.

TABLE 26

EQUIPMENT	Exposure (Hours)	Corrosion Rate (Ipy)
Reactor	5220	0.18
Pipe-still tubes (straight)	5220	0.18
Pipe-still tubes (U-bend)	5220	0.12
Furnace transfer line	2491	0.45
Furnace transfer line	2729	0.25
Reactor internal	832	0.34

Ref. B-8 British Petroleum Company Ltd. Corrosion Test Specimens in Autofining Pilot Plant at Grangemouth, Scotland (Feb. 1950).

Table 27 lists the corrosion rates obtained from test pieces exposed in the Autofiner pilot plant for periods up to about 100 days.

TABLE 27

Location	Material	Number of Samples	EXPOSURE (Hours) React.	Regen.	Temp. (Deg. F)	H_2S Partial Pressure (Psia)	Average Corrosion Rate (Ipy)
Reactor	Carbon steel	4	2491	600	780	15.0	0.145
Reactor	1 Cr—½ Mo	1	378	75	780	15.0	0.133
Reactor	2 Cr—½ Mo	1	378	75	780	15.0	0.151
Reactor	5 Cr—½ Mo	1	378	75	780	15.0	0.139
Reactor	7 Cr—½ Mo	1	378	75	780	15.0	0.093
Reactor	CalorizedC.S.	4	1800	600	780	15.0	0.001
K. O. Tower	Carbon steel	2	629	..	425	15.0	0.008[1]
K. O. Tower	Carbon steel	1	629	..	425	15.0	0.024[2]
K. O. Tower	Carbon steel	1	629	..	600	15.0	0.139[1]

[1] (Vapor)
[2] (Liquid)

Ref. B-9 British Petroleum Company Ltd. Corrosion of Aluminum Coated Steels under Autofining Conditions (April 1952).

Table 28 is a summary of a series of laboratory scale tests in which different types of aluminum protected steel samples were exposed for 48 hours to a 50:50 hydrogen sulfide-hydrogen mixture at 800 F and 500 psig.

In semi-commercial Autofining operation, calorized equipment has not given satisfactory service, primarily because the coating tends to spall at locations not easily accessible to or protected by calorizing.

TABLE 28

MATERIAL	Corrosion Rate (Ipy)
Bare carbon steel	0.12
Bare 18 Cr—8 Ni steel	0.015
Calorized carbon steel	Nil
Al-Cd sprayed C.S.	0.020
Al powder sprayed C.S.	0.046

Ref. B-10 D-X Sunray Oil Company. Inspection of Catalytic Reforming Unit at Tulsa, Oklahoma (Feb. 1955).

Measurements on sectioned 5 Cr-1/2 Mo tubes from the hottest reactor feed—reactor effluent exchanger indicated the rates given in Table 29[11] the hydrogen sulfide content on both sides of the exchanger corresponded approximately to 0.04 percent by volume (0.16 psia hydrogen sulfide partial pressure). The chemical composition of the corrosion scale was principally FeS.

TABLE 29

Temperature (Degrees F)	Corrosion Rate (Ipy)
Approximately 870	0.04
Approximately 600	0.01

Ref. B-12 Pure Oil Company. Inspection of Catalytic Reforming Unit at Heath, Ohio (June 1955).

After eight months of operation, the unit was opened for inspection following a light regeneration burn. The estimated minimum corrosion rate in the 2 Cr-1/2 Mo preheater furnace tubes is 0.033 ipy, as based on observed thickness and analysis of internal corrosion scale (FeS and Fe_2O_3). The corresponding conditions of skin temperature and hydrogen sulfide partial pressure were approximately 1000 F and 0.15 psia hydrogen sulfide.

Ref. B-13 Pure Oil Company. Corrosion Test Specimens in Catalytic Reforming Unit at Heath, Ohio (Nov. 1955).

Corrosion test pieces installed in the unit for 130 days gave the results summarized in Table 30.

Ref. B-14 Shell Oil Company. Inspection of Platformer at Wood River, Ill.

Based on one year's exposure to an atmosphere containing 0.07 vol. percent (0.37 psia) hydrogen sulfide, the corrosion rate on 5 Cr-1/2 Mo piping amounted to about 1/8 ipy at 925 F, and to about 0.10 ipy at 700 F. The 9 Cr-1 Mo furnace tubes showed a corrosion rate of about 0.035 ipy at 1000-1050 F.

Ref. B-15 Shell Oil Company. Corrosion Test Specimen in Platformer at Wood River, Ill.

Corrosion test pieces installed in the unit for about four months at approximately 925 F and 0.37 psia hydrogen sulfide, yielded the corrosion rates listed in Table 31.

Ref. B-16 Sinclair Refining Company. Inspection of Catalytic Reforming Unit at Marcus Hook, Pa. (1955).

The unit was inspected both after the first and second regenerations. At the end of the initial 120 day run, corrosion rates were estimated from the thickness and composition (principally Fe_2O_3) of corrosion

(11) The condition of the exchanger bundle is shown in Figure 1.

scales which had built up on 5 Cr-1/2 Mo piping and 12 Cr reactor internals. These estimated corrosion rates as well as those obtained after the second run of about five months duration are listed in Table 32. The hydrogen sulfide content in the unit was approximately 0.005 vol. percent (0.025 psia hydrogen sulfide partial pressure).

TABLE 30

LOCATION	CORROSION RATE (Ipy) Predesulfurizer Effluent Exch.	Reformer Effluent Exch.	Predesulfurizer Reactor	Reformer Effluent Exch.
Temperature	**555 F**	**650 F**	**650 F**	**800 F**
Pressure	**100 Psig**	**450 Psig**	**400 Psig**	**450 Psig**
H_2S, Percent Volume	**0.080**	**0.026**	**0.035**	**0.026**
H_2S, Partial Pressure	**0.088 Psia**	**0.12 Psia**	**0.15 Psia**	**0.12 Psia**
Carbon steel	0.0029	0.0152	0.0215	0.0220
1 Cr—½ Mo	0.0021	0.0071	0.0193	0.0126
2¼ Cr—1 Mo	0.0022	0.0116	0.0200	0.0165
5 Cr—½ Mo	0.0026	0.0044	0.0238	0.0236
9 Cr—1 Mo	0.0015	0.0070	0.0164	0.0124
12 Cr	0.001	0.0082	0.0089	0.0151
18 Cr—8 Ni	<0.001	<0.001	<0.001	0.0013
18 Cr—8 Ni—3 Mo	<0.001	<0.001	<0.001	0.0012
25 Cr—20 Ni	<0.001	<0.001	<0.001	<0.001
Incoloy (22 Cr—32 Ni)	<0.001	<0.001	<0.001	<0.001
Inconel (16 Cr—76 Ni)	<0.001	<0.001	0.002	<0.001

TABLE 31

MATERIAL	CORROSION RATE (Ipy) Run 1	Run 2	Average
Carbon steel	0.032	0.047	0.039
1¼ Cr—½ Mo	....	0.047	0.047
2¼ Cr—1 Mo	....	0.050	0.050
5 Cr—½ Mo	0.038	0.047	0.043
7 Cr—½ Mo	0.037	0.044	0.040
9 Cr—1 Mo	0.034	....	0.034
12 Cr	0.015	0.022	0.018
18 Cr—8 Ni	0.0043	0.0072	0.0058

TABLE 32

MATERIAL	Location	Temperature (Degrees F)	Run	Corrosion Rate (Ipy)
5 Cr—½ Mo	Piping	900—950	1	0.007
5 Cr—½ Mo	Piping	900—950	2	0.01
5 Cr—½ Mo	Furnace	975—1025	2	0.01
12 Cr	Reactor	900—950	1	0.005
12 Cr	Reactor	900—950	2	0.008

Ref. B-17 Socony Mobil Oil Company. Inspection of TCR Unit at Torrance, California.

Approximate corrosion rates measured on this unit operated by the General Petroleum Company are listed in Table 33. The approximate conditions are 175 psig pressure and 1.5-2.0 percent hydrogen sulfide by volume.

TABLE 33

	Corrosion Rate (Ipy)	
Temperature	**950 F**	**1050 F**
H_2S Part. Press.	**3 Psia**	**3 Psia**
5 Cr—½ Mo	0.2	0.3
12 Cr	0.06	0.08
18 Cr—8 Ni	0.01	0.02

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Publication 56-8

High Temperature Hydrogen Sulfide Corrosion In Thermofor Catalytic Reformers*

A Contribution to the Work of NACE Task Group T-5B-2 on Sulfide Corrosion At High Temperatures and Pressures in the Petroleum Industry from: Socony Mobil Oil Co., Inc., Research and Development Laboratory, Paulsboro, N. J.

By E. B. Backensto,(1) R. D. Drew,(1) R. W. Manuel(2) and J. W. Sjoberg.(1)

Abstract

High temperature hydrogen sulfide corrosion is a serious problem in commercial reforming units. Corrosion tests conducted in two Thermofor catalytic reformers, which handle widely different type stocks, have shown that carbon and low chrome steels commonly used for construction in the petroleum industry will not resist hydrogen sulfide attack under the high temperature conditions of the process. The commercial tests confirmed laboratory results which indicated that only the 18-8 chrome-nickel and higher alloys show good resistance to this type of corrosion.

In addition to proper selection of alloys, altering the environment by reducing hydrogen sulfide concentration and the use of aluminum coated steels have been successful in combating this type of corrosion.

Introduction

CATALYTIC REFORMING is one of the key processes employed in the manufacture of modern high octane gasoline. The catalyst is the heart of the process, for in a hydrogen atmosphere it promotes the desired chemical rearrangement of the hydrocarbon molecules and removal of sulfur. The end result is improved octane number and reduced sulfur content.

Several competitive catalytic reforming processes have been developed and put into commercial operation. Although all of these processes have a common purpose, they vary considerably in catalyst and conditions used, physical arrangement and process flow. The type of charge stock they can handle most efficiently also may vary.

The Thermofor catalytic reforming (TCR) process[1] was developed by Socony Mobil Oil Company for handling a wide variety of charge stocks including high sulfur, low quality coker gasoline. This process employs the moving compact bed principle used in the Thermofor catalytic cracking (TCC) process. The catalyst consists of synthetic beads of cogelled chromia and alumina[2] and is regenerated continuously in the process. When the charge naphtha contacts the catalyst in the reactor, desulfurization of the feed is accomplished, the sulfur being converted principally to hydrogen sulfide. Because some of the hydrogen sulfide is returned in the hydrogen-rich recycle gas stream, the hydrogen sulfide level in the gas recycle system and reactor effluent can be relatively high.

The original construction materials for the commercial TCR units were selected largely from the low chromium alloys. These steels are commonly used in other petroleum equipment for protection against high temperature corrosion by sulfur-bearing oils, and were expected to exhibit reasonably good resistance to hydrogen sulfide. They were known to resist high temperature hydrogen attack.

The first TCR unit, capacity 19,500 barrels per day, was put on-stream in the summer of 1954 at the Torrance, California, refinery of General Petroleum Corporation. The charge stock contained approximately 0.8 percent sulfur by weight. The hydrogen sulfide level built up to about 2 percent by volume in the recycle gas and 2.5 percent by volume in the reactor effluent. The second TCR, of the same capacity, was put on-stream in the spring of 1955 at the Beaumont, Texas, refinery of Magnolia Petroleum Company. The sulfur content of the charge stock was considerably lower than at Torrance, being about 0.1 percent by weight.

The Problem

At the TCR operating temperature and pressure, hydrogen sulfide caused unexpectedly rapid scale formation on the low chromium steels in the first unit. However, the rapid growth of scale and detrimental effects inside the equipment were not evident immediately.

After a month and a half of operation the unit was

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(1) Socony Mobil Oil Co., Inc., Research and Development Laboratory, Paulsboro, N. J.

(2) Socony Mobil Oil Co., Inc., 26 Broadway, New York, N. Y.

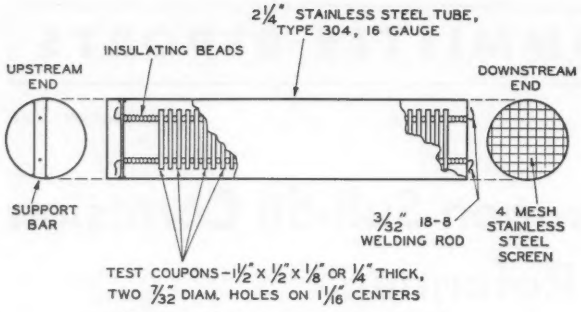
2¼" STAINLESS STEEL TUBE, TYPE 304, 16 GAUGE
INSULATING BEADS
UPSTREAM END
DOWNSTREAM END
SUPPORT BAR
3/32" 18-8 WELDING ROD
4 MESH STAINLESS STEEL SCREEN
TEST COUPONS - 1½" x ½" x ⅛" OR ¼" THICK, TWO 7/32" DIAM. HOLES ON 1 1/16" CENTERS

Figure 1—Sketch of corrosion test rack.

shut down for inspection and equipment modifications. When the unit was started up again, large pieces of scale flaked off of the internal surfaces, causing restriction of catalyst flow and a forced shutdown. Examination of the unit showed that in the hottest sections of the unit, the scale was 0.1 inch thick. Metal loss measurements indicated corrosion rates on the low chromium alloys of 0.25 inch per year or more. The problem was one of high temperature hydrogen sulfide corrosion in a hydrogen atmosphere.

The Approach

The problem was handled in three ways. First, laboratory corrosion test units were set up to study metal corrosion under specific conditions of temperature, pressure, and hydrogen sulfide concentration. At the same time, metal test specimens, ranging from carbon steel to the 25-20 chromium-nickel stainless steels, were placed in various laboratory pilot units used for reforming and hydrogenation studies. Similar coupons were prepared for placement in commercial catalytic reforming units to obtain data under actual operating conditions.

A summary of the first phase of this work, the laboratory studies, was reported last October.[3] Initial data from this study were used as a guide for providing corrosion protection to the two TCR units. Before the Torrance unit was put back on-stream, the following steps were taken:

1. An amine scrubber was installed to lower the hydrogen sulfide concentration in the recycle gas from about 2 to 0.03 percent by volume.
2. All hot transfer lines were calorized to eliminate sulfide scaling in these areas.
3. Critical sections of the reactor and kiln were replaced with 18-8 chromium-nickel stainless steel to minimize corrosion.

Scope of Report

This paper summarizes results of initial corrosion tests conducted in both the Torrance and Beaumont TCR units. The first test, in the Torrance TCR unit, included ten test racks located in critical sections of the unit; each corrosion rack contained between 25 and 30 test coupons. The second test, at Beaumont, was similar to the Torrance test.

Test Procedure

The test coupons measuring 1½x½ inches were cut from ⅛ or ¼ inch plates; two mounting holes were drilled near the ends. The chemical analyses of the various metals used in these tests are summarized in Table 1.

The test coupons were mounted on two 18-8 welding rods inside a test rack as shown in Figure 1. The coupons were supported on the welding rods and separated from each other by porcelain beads. The downstream end of the test rack tube was fitted with a 4 mesh stainless steel screen. The test racks were tack-welded with a 25-20 welding rod on the side of the transfer lines near a flange or on a convenient support member in the unit.

After the test period the coupons usually looked

TABLE 1—Chemical Analyses of Metals Used in Corrosion Tests

MATERIAL	Supplier	Heat Number	CHEMICAL ANALYSES (BALANCE FE), PERCENT WEIGHT												
			C	Cr	Ni	Mo	Mn	P	S	Si	Al	Cu	Ta	Cb	Ti
Carbon Steel-ASTM A7	Morris Wheeler & Co.	.....	0.20-0.35	.....	.....	.....	.....	0.10 Max.	0.05 Max.	.....	.....	.....	.....	.....	.....
Carbon Steel-ASTM-A83 Type A	Hill Chase	.....	0.06-0.18	.....	.....	.....	0.27-0.63	0.048 Max.	0.058 Max.	.....	.....	.....	.....	.....	.....
Carbon Steel-ASTM-A201-Grade A	Morris Wheeler & Co.	23522K	0.19	.....	.....	.....	0.48	0.010	0.024	0.20	.....	.....	.....	.....	.....
Carbon Steel-ASTM-A285-Grade C	Morris Wheeler & Co.	13412	0.16	.....	.....	.....	0.38	0.014	0.040	.....	.....	.....	.....	.....	.....
1 Cr—½ Mo	Timken Roller Bearing Co.	14856	0.10	0.97	.....	0.55	0.36	0.011	0.014	0.25	.....	.....	.....	.....	.....
1¼ Cr—½ Mo	Timken Roller Bearing Co.	17990	0.09	1.20	0.27	0.53	0.50	0.013	0.014	0.70	.....	.....	.....	.....	.....
2¼ Cr—1 Mo	Timken Roller Bearing Co.	23237	0.11	2.36	0.24	1.02	0.30	0.018	0.017	0.34	.....	.....	.....	.....	.....
5 Cr—½ Mo (a)	G. O. Carlson Co.	RO-45485-6A	0.06	4.96	0.10	0.49	0.39	0.023	0.023	0.31	.....	.....	.....	.....	.....
5 Cr—½ Mo (b)	Allegheny	87657	0.087	5.34	0.20	0.48	0.39	0.015	0.018	0.47	.....	.....	.....	.....	.....
5 Cr—½ Mo (c)	(Refinery Stock)	.....	0.08	4.72	.....	0.54	0.44	0.013	0.019	0.15	.....	.....	.....	.....	.....
7 Cr—½ Mo	Timken Roller Bearing Co.	23379	0.125	6.35	0.15	0.54	0.36	0.014	0.025	0.84	.....	.....	.....	.....	.....
9 Cr—1 Mo	Timken Roller Bearing Co.	11977	0.11	8.03	0.48	0.97	0.48	0.019	0.011	0.68	.....	.....	.....	.....	.....
12 Cr—Type 405	G. O. Carlson Co.	52426-2A	0.048	12.47	0.30	.....	0.76	0.016	0.015	0.51	0.22	.....	.....	.....	.....
12 Cr—Type 410 (d)	G. O. Carlson Co.	54034-1A	0.069	12.71	0.31	0.44	0.39	0.018	0.017	0.39	.....	0.14	.....	.....	.....
12 Cr—Type 410 (e)	Allegheny	16110	0.07	12.02	0.20	.....	0.37	0.018	0.020	0.43	.....	.....	.....	.....	.....
16 Cr—Type 430	G. O. Carlson Co.	54137	0.088	17.82	0.33	.....	0.58	0.020	0.014	0.46	.....	0.12	.....	.....	.....
18-8—Type 302	Allegheny	42950	0.086	17.57	8.71	.....	0.85	0.028	0.022	0.41	.....	0.23	.....	.....	.....
18-8S—Type 304	G. O. Carlson Co.	64343-2B	0.055	18.56	9.42	.....	0.67	0.030	0.025	0.44	.....	0.25	.....	.....	.....
18-8SL—Type 304L	G. O. Carlson Co.	64541-2B	0.028	18.29	9.44	.....	1.09	0.024	0.013	0.39	.....	0.19	.....	.....	.....
18-8M—Type 316	G. O. Carlson Co.	64073-1C	0.041	17.78	12.93	2.42	1.84	0.023	0.017	0.70	.....	0.20	.....	.....	.....
18-8ML—Type 316L	G. O. Carlson Co.	64307-2	0.019	17.60	13.80	2.75	1.50	0.021	0.019	0.55	.....	0.34	.....	.....	0.33
18-8T—Type 321	G. O. Carlson Co.	9616	0.062	18.14	9.48	.....	1.38	0.017	0.005	0.67	.....	.....	.....	.....	.....
18-8C—Type 347	G. O. Carlson Co.	54708-1A	0.060	18.69	11.29	.....	1.65	0.022	0.012	0.68	.....	0.23	0.13	0.69	.....
25-12—Type 309	G. O. Carlson Co.	54580-2A	0.060	22.24	14.62	.....	1.93	0.020	0.014	0.46	.....	0.17	.....	.....	.....
25-12C—Type 309 CBS	G. O. Carlson Co.	53785-2D	0.057	23.05	15.48	.....	1.81	0.021	0.019	0.52	.....	.....	0.08	0.54	.....
25-20—Type 310	G. O. Carlson Co.	54038-1B	0.060	24.76	20.07	.....	1.25	0.021	0.015	0.55	.....	0.12	.....	.....	.....
Monel	Whitehead Metals Prod. Co.	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....

about like those shown in Figure 2. The specimens were removed from the rack, freed of corrosion products, and weighed. The weight loss and original surface area of the coupons were used to calculate the corrosion rates, reported as inches penetration per year.

Heavy loose scale is easily removed from corrosion test coupons. However, a thin tightly adhering scale then remaining is quite difficult to remove. Several methods of scale removal have been investigated. The procedure which has given the best results has been standardized as follows:

1. Coupons are allowed to cool so that most of the heavy scale flakes off.
2. The remainder of the heavy, loose scale is removed with a knife.
3. As much of the remaining scale as possible is then removed with a 6-inch circular wire brush (Black & Decker No. 23211 steel brush rotated at about 1200 rpm by a small laboratory stirrer motor).
4. Specimens are then soaked for 30 minutes at room temperature with mild agitation in a bath of 20 percent Oakite No. 32 (inhibited HCl), rinsed, and dried.
5. Steps 3 and 4 are then repeated. This method gives essentially complete scale removal with negligible loss of base metal.

Test Results

The results of the initial tests in the two TCR units will be discussed in three parts: (1) Metal corrosion rate results, (2) A comparison of laboratory with field data, and (3) Evaluation of aluminum coatings under field conditions.

Torrance TCR Test

A simplified flow diagram of the hot sections of the TCR unit is shown in Figure 3. The catalyst flow is marked by a broken line. From the reactor the catalyst passes through a depressuring leg before being regenerated in the kiln. The continuous cycle is completed by passing the catalyst through a pressuring sphere and then back into the reactor. The solid flow lines indicate the path of the hydrocarbon streams. On the way to the furnace the recycle picks up heat from the reactor effluent. The heated recycle gas combines with the naphtha charge on entering the reactor. The charge stream splits within the reactor, part leaving at the top and the other part at the bottom. The combined reactor effluent passes through a cooler, is stabilized, and finally blended to product specifications.

The asterisks on the flow diagram indicate the corrosion test rack locations. Average operating conditions for the 55 day exposure are shown opposite each test point. The temperature is an average value from the daily log. The hydrogen sulfide concentration was estimated from occasional gas analysis.

Figure 2 shows test racks exposed in the Torrance TCR unit. The flaky nature of the scale can be seen

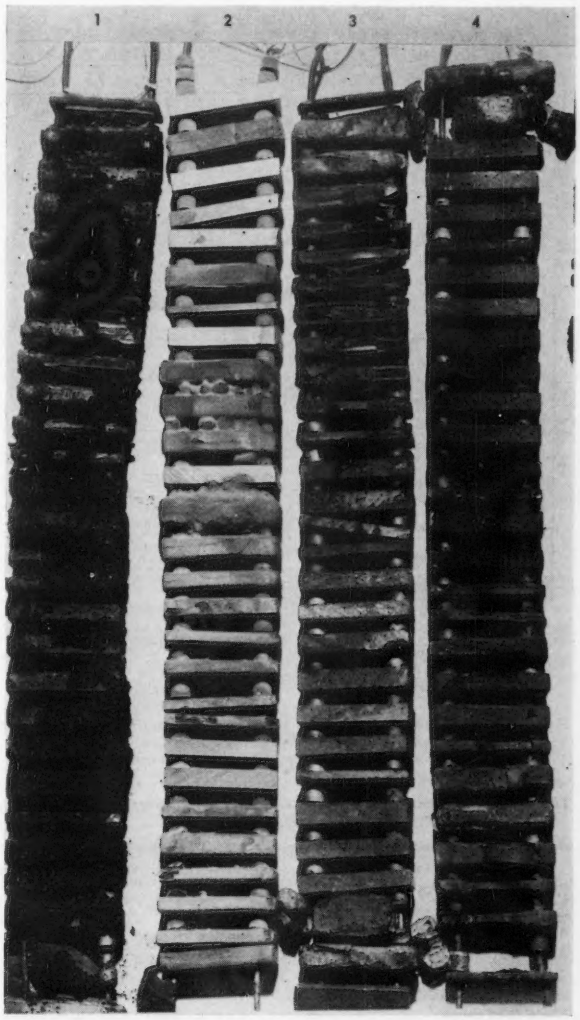

Figure 2—Corrosion test racks after 55-day exposure in Torrance TCR Unit. Test locations were as follows: Rack No. 1, reactor inlet; Rack No. 2, top reactor outlet; Rack No. 3, bottom reactor outlet; Rack No. 4, mixed reactor effluent line.

on several test coupons. Reading from left to right, these test racks were exposed at the following locations: Reactor inlet, top reactor outlet, bottom reactor outlet, and mixed reactor effluent line. The lumps of material seen at the bottom of the first three racks and at the top of the fourth are the remains of Monel test coupons which were destroyed at the test conditions.

Corrosion results from the Torrance TCR unit are shown for one test rack in Table 2. Note the similarity in the corrosion rate results within the group of 0.9 percent chromium steels and the group of chromium-nickel alloys. No definite advantage is shown for the extra low carbon stainless steels over the more conventional types. The conclusions drawn from commercial unit test results for the selection of steels agree with those reported previously from laboratory tests.[3]

Figure 3 also shows a summary of corrosion rates obtained at all test locations. In general the metals

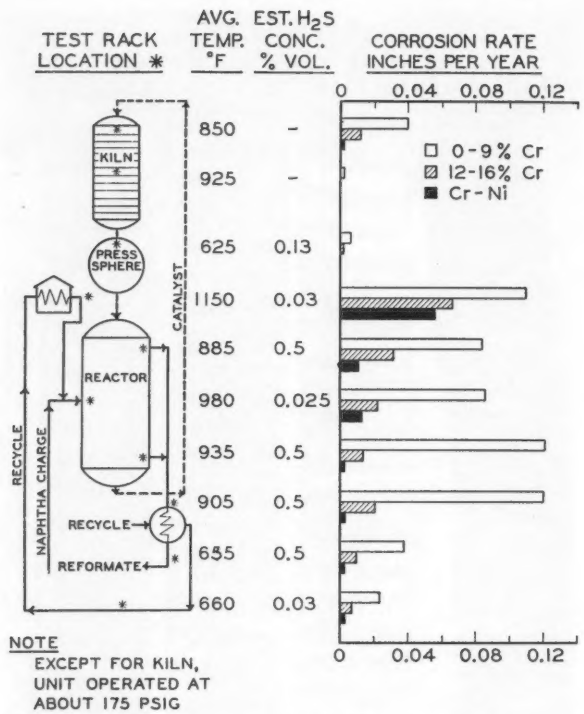

Figure 3—Summary of corrosion rates for 55-day test in Torrance TCR unit.

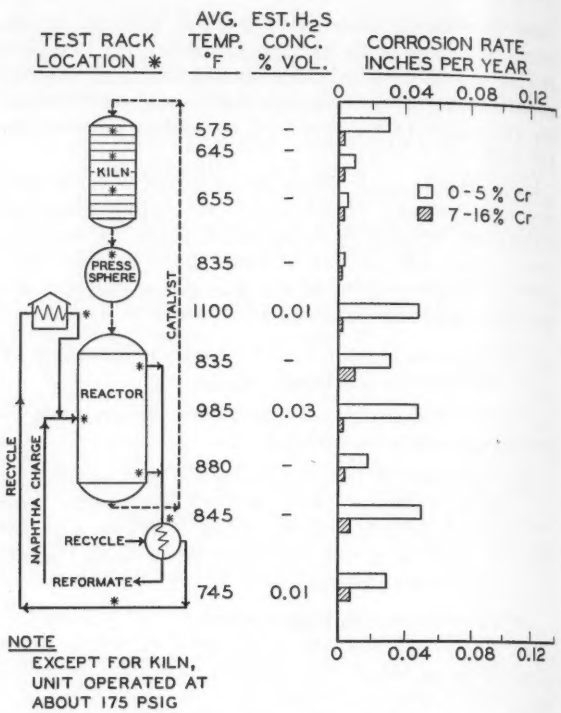

Figure 4—Summary of corrosion rates for 29-day test in Beaumont TCR unit.

TABLE 2—Corrosion Test Results from Highest Temperature Section of TCR Units

LOCATION	Outlet of Recycle Heater	
UNIT	Torrance	Beaumont
Average Conditions:		
Temperature, Degrees F	1150	1100
Pressure, psig	190	170
H_2S, Percent by Volume	0.03	0.009
Exposure Time, Days	55	29
Material Tested	**Corrosion Rate, IPY**	
Carbon Steel—ASTM A7	0.105	0.0512
Carbon Steel—ASTM A83-A	0.128	0.0543
Carbon Steel—ASTM A201-A	0.092	0.0505
Carbon Steel—ASTM A285-C	0.102	0.0530
1 Cr—½ Mo	0.112	0.0498
1¼ Cr—½ Mo	0.129	0.0493
2¼ Cr—1 Mo	0.124	0.0449
5 Cr—½ Mo (a)	0.112	0.0241
5 Cr—½ Mo (b)	0.103	0.0178
5 Cr—½ Mo (c)	0.106	0.0143
7 Cr—½ Mo	0.101	0.0016
9 Cr—1 Mo	0.102	0.0019
12 Cr—Type 405	0.0716	0.0002
12 Cr—Type 410 (d)	0.0767	0.0001
12 Cr—Type 410 (e)	0.0691	0.0006
16 Cr—Type 430	0.0423	0.0005
18-8—Type 302	0.0704	0.0004
18-8S—Type 304	0.0578	<0.0001
18-8SL—Type 304L	0.0588	<0.0001
18-8M—Type 316	0.0589	<0.0001
18-8ML—Type 316L	0.0628	<0.0001
18-8T—Type 321	0.0478	<0.0001
18-8C—Type 347	0.0566	<0.0001
25-12—Type 309	0.0375	<0.0001
25-12C—Type 309 CBS	0.0371	<0.0001
25-20—Type 310	0.0629	<0.0001
Monel	*	0.182

* Sample destroyed in test.

fell into three natural groupings with respect to corrosion rate (see Table 2). The results are presented graphically for these three groups; namely, carbon and low chromium steels (0-9 percent chromium), intermediate chromium steels (12-16 percent chromium), and the chromium-nickel stainless steels.

The results show that above 800 F, even at a hydrogen sulfide level of only 0.025 percent by volume, the corrosion rates for carbon and low chromium steels are quite high. The best corrosion resistance was afforded by the chromium-nickel alloys. Additional remarks concerning the results at each test location follow.

In the kiln, the corrosion test racks were placed in the off-gas channels. Here the operation is near atmospheric pressure. The top zone of the kiln, where any sulfur on the catalyst is removed preferentially, contains the most corrosive gas.

During the test period the catalyst pressuring sphere was pressurized largely with sweet gas. Sour gas containing up to 0.2 percent by volume hydrogen sulfide was used intermittently. Because of the relatively low temperature, the corrosion rates are low at this point.

The hottest test point was at the recycle heater outlet. Of particular interest is the unusually high corrosion rate observed for the chromium-nickel alloys, which is about one-half the rate for the carbon and low chromium steels. This is confirmed qualitatively by Penetron measurements made on the recycle gas heater tubes after 100 days of operation. These measurements indicated corrosion rates up to 0.26 inches per year in both the 9 percent chromium and Type 321 stainless steel tubes. To study this behavior of chromium-nickel steels further, laboratory tests have been made at 1500 F in hydrogen-hydrogen sulfide atmospheres. These tests show that at this higher temperature level, stainless steel corrosion rates are actually *greater* than those for the low chrome steels (Table 3).

At the reactor inlet and outlets (Figure 3), the carbon and low chromium steels exhibit relatively high corrosion rates for temperatures of 885-980 F. At these points, the austenitic chromium-nickel alloys show good corrosion resistance.

The corrosion rates were relatively low at the remaining two test locations; namely, the reactor effluent after heat exchange and the inlet to the recycle heater. The temperature of 660 F accounts for the lower corrosion rates.

Beaumont TCR Test

Corrosion experience with the Torrance TCR unit was used to advantage in the Beaumont unit. Before start-up, critical portions of the Beaumont unit were replaced with chromium-nickel alloys. The charge stocks and operating conditions in this unit are such that the hydrogen sulfide content of the recycle is quite low. For these reasons, no serious high temperature hydrogen sulfide corrosion problem has been encountered in the Beaumont unit.

During the test period occasional hydrogen sulfide analyses were obtained only in the recycle gas stream. These analyses ranged from zero to 0.02 percent by volume hydrogen sulfide (weighted average, 0.009 percent hydrogen sulfide by volume). The hydrogen sulfide content fluctuated because a wide variety of naphtha blends were charged to the unit during the test period. The sulfur content of the charge stock varied from 0.03 percent by weight to ten times this value.

Corrosion test results for the 29-day test period are summarized in Table 2. These test coupons were at the hottest test point, the recycle heater outlet. In all cases where the corrosion rates were greater than 0.01-0.02 inch per year, the test coupons contained flaky corrosion scale. The carbon and low chromium steels exhibited the highest corrosion rates. The 5 percent chromium steels showed some improvement over the lower chromium steels. Increasing the chromium content of the steels improved the corrosion resistance; definite levels of improvement were shown first for the 7-9 percent chromium steels and next for the 12-16 percent chromium steels.

The relative corrosion rates found in the commercial unit confirm laboratory test results. Laboratory results at low hydrogen sulfide concentrations usually show a similar pattern of decreasing corrosion rates with increasing chromium content of the steels. At high hydrogen sulfide concentrations, even 12 percent chromium steels often offer little advantage over carbon steel.

At most locations in the Beaumont unit the metals fell into three more or less distinct corrosion rate groupings, corresponding to 0.5 percent chromium steels, 7-16 percent chromium steels, and chromium-nickel alloys. A summary of the Beaumont data is shown in Figure 4. Only results for the 0-5 percent and 7-16 percent chromium steel groups are shown because the corrosion rates for chromium-nickel alloys were too low to plot, generally being less than 0.0005 inch per year.

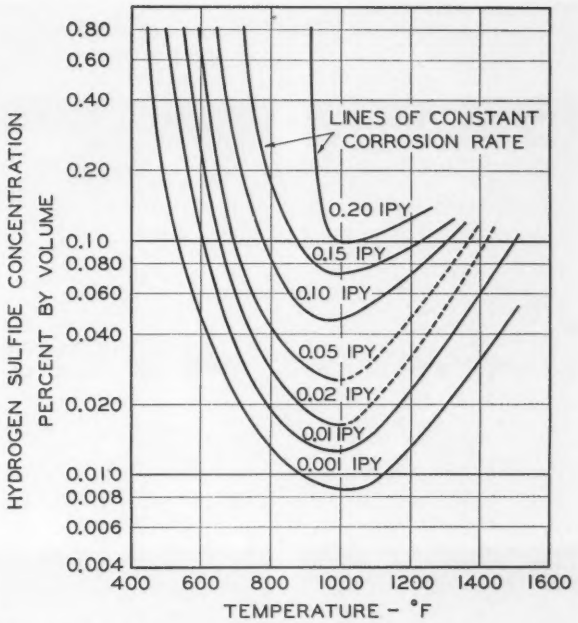

Figure 5—Effect of temperature and hydrogen sulfide concentration on corrosion rate of 0-5 percent chromium steels. Graph is from laboratory data at 175 to 500 psig hydrogen pressure.

TABLE 3—Laboratory Data on High Temperature Corrosion of Chromium and Chromium-Nickel Steels

Average Conditions	Test 1	Test 2
Temperature, Degrees F	1495	1488
Hydrogen Pressure, psig	180	180
H_2S in Hydrogen, Percent by Volume	0.05	0.15
Exposure Time, Hours	117	114
Materials Tested	**Corrosion Rate, IPY**	
2¼ Cr—1 Mo	0.0013	0.0059
5 Cr—½ Mo (a)	0.0036; 0.0027	0.0193
9 Cr—1 Mo	0.0086	0.0360
18-8S—Type 304	.....	0.0694
18-8SL—Type 304L	0.0056	0.0641
18-8T—Type 321	0.0116	0.0369
25-12—Type 309	0.0196	0.0561
25-12C—Type 309 CBS	0.0258	0.0691
25-20—Type 310	0.0131	0.147

Factors other than temperature can affect corrosion rate. For example, a high corrosion rate was observed at the top of the kiln where temperatures were quite low. This is believed to result from high concentrations of sulfur containing gas at this point. In the top reactor outlet line the corrosion rates were higher than in the bottom outlet even though the temperature was lower. This is probably due to a higher water concentration in the top of the reactor, where oxygen entrained in the incoming catalyst is converted to water.

To obtain additional information over extended operating periods, replacement test racks were put in both the Torrance and Beaumont TCR units.

Comparison of Laboratory with Field Data

As already indicated, laboratory corrosion tests agree fairly well with results obtained in the commercial TCR units. In the field as in the laboratory under similar conditions, the chromium-nickel alloys afforded the best corrosion protection at all condi-

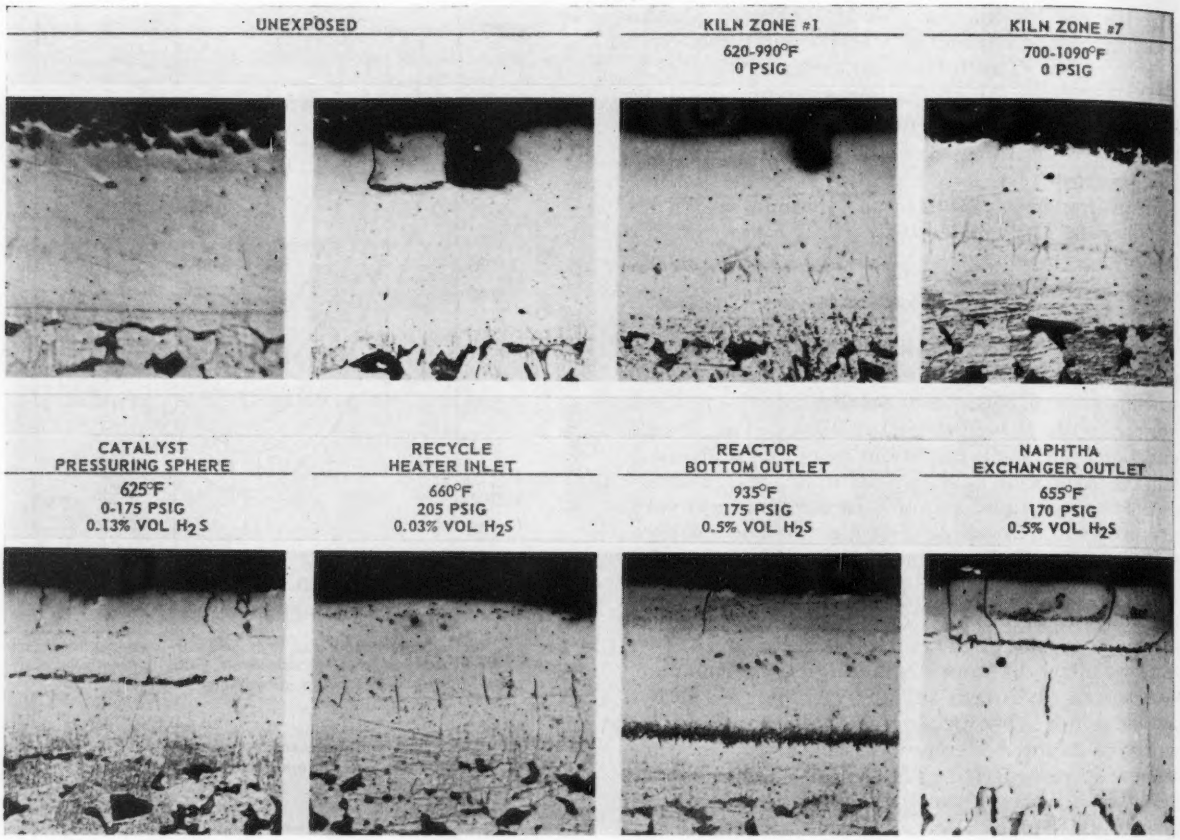

Figure 6—Photomicrographs of calorized carbon steel exposed for 55 days in Torrance TCR unit. 80X, nital etch.

tions tested. The group of 0-5 percent chromium steel exhibited the highest corrosion rates. The group of 7-16 percent chromium steels were unpredictable but gave results falling between the rates for the other two groups. At similar temperatures and pressures, corrosion rate increased with hydrogen sulfide concentration. Also, at the same hydrogen sulfide concentration, corrosion rate increased with temperature. Whenever flaky corrosion scale was found on the test coupons the measured corrosion rate was above 0.01 inch per year.

Figure 5 summarizes the laboratory corrosion rate data on the 0-5 percent chromium steels. (Actually under many conditions this group might also include 7 and 9 percent chrome steels). The curves are based on the results of approximately 50 test runs which included some 300 individual test specimens. The major variables plotted are temperature and hydrogen sulfide concentration with curves showing constant corrosion rate. The pressure variable was confined to the range of 175-500 pounds per square inch gauge because limited data at 0.1 percent hydrogen sulfide by volume and 985 F indicated that corrosion rate is unaffected by pressure in this range. Actually, most of the data below 1000 F were obtained at 465-485 pounds per square inch while above 1000 F they were at 175-185 pounds per square inch.

For hydrogen sulfide concentrations below about 0.1 percent by volume, these curves (Figure 5) show that as temperature is increased, corrosion rate passes through a maximum at about 1000 F. Considering 0.01 inch per year as the level where flaky scale forms, the corresponding percent volume hydrogen sulfide, according to this graph, would be 0.01, 0.02, and 0.1 at 1000, 800 and 600 F, respectively.

When comparing laboratory data with field tests, it is important to remember that the laboratory data were obtained under controlled conditions whereas commercial conditions often include necessary changes. It might be pointed out also that the short-term laboratory corrosion rates were expected to be somewhat higher than for long-term field tests.

During the Torrance TCR test period reported in Figure 3, hydrogen sulfide determinations were not made on a routine basis at all test locations. For example, only the combined reactor effluent stream could be analyzed and the hydrogen sulfide concentration in the top reactor outlet may have been substantially less than in the lower reactor outlet. Also, the results obtained showed wide fluctuations—for short periods the hydrogen sulfide concentration in the recycle stream was three to four times the value shown. Thus, the hydrogen sulfide values shown represent a reasonable estimate for normal operating conditions, but the actual average concentrations could be considerably different. Considering all these factors, predictions based on laboratory data were reasonably sound.

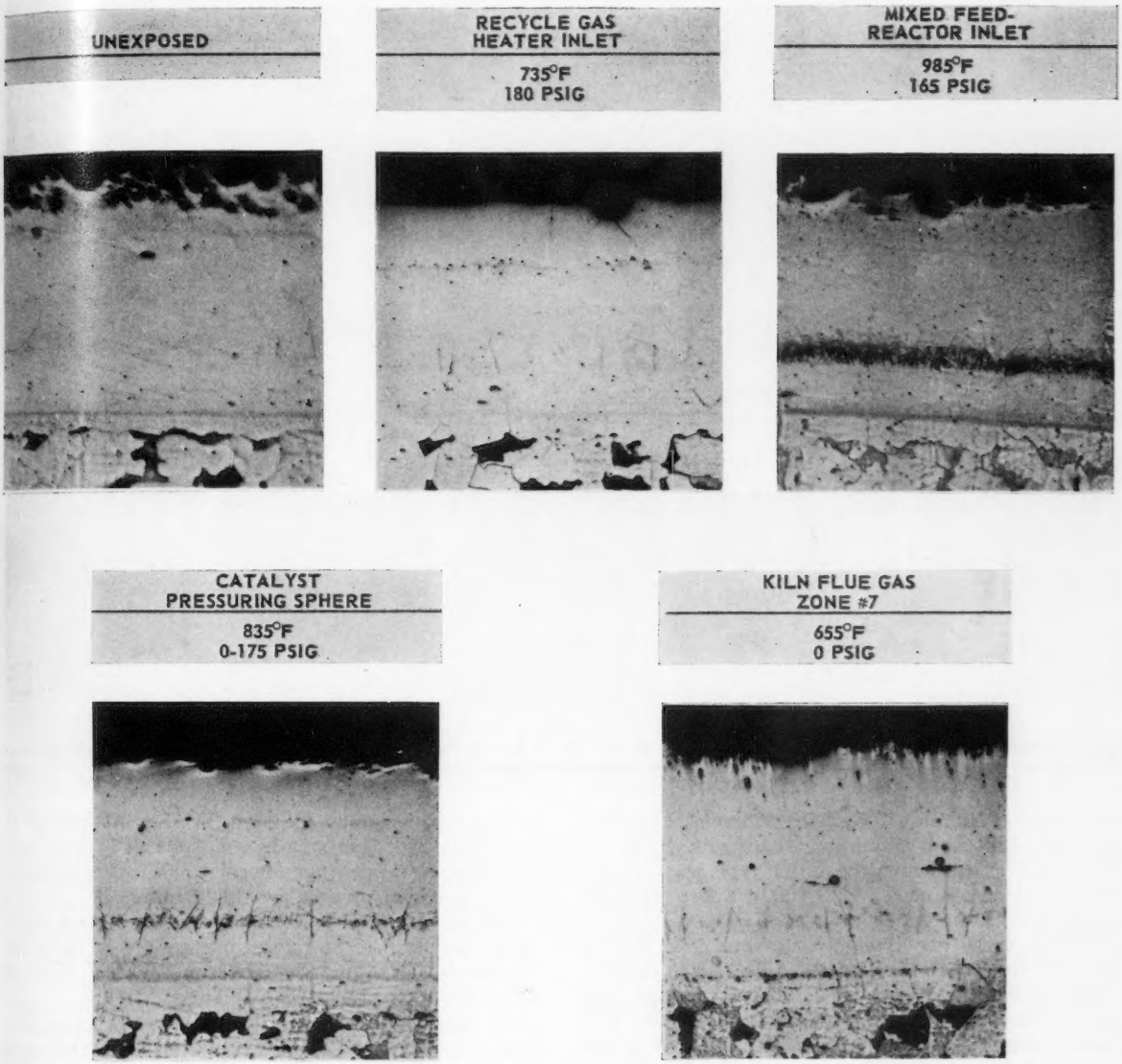

Figure 7—Photomicrographs of calorized carbon steel specimens exposed for 29 days in Beaumont TCR unit. Recycle gas averaged 0.009 percent hydrogen sulfide by volume. 100X, nital etch.

Only limited analytical data under changing conditions are available for the Beaumont TCR unit test period reported in Figure 4. As stated before, the weighted average hydrogen sulfide concentration in the recycle gas was 0.009 percent by volume. At times, however, the recycle gas contained no hydrogen sulfide. Laboratory tests have shown that the initial corrosion rate is high and the iron sulfide scale that forms offers some protection to further corrosion. Once scale forms and the hydrogen sulfide is removed, the hydrogen in the system can react with the iron sulfide to form a very reactive iron surface while releasing hydrogen sulfide. Thus any protection offered by the scale is diminished.

When hydrogen sulfide is alternately present and absent, even though scale is present, the corrosion rate would be much higher than for a constant hydrogen sulfide level. Hence, under the fluctuating conditions in the Beaumont TCR unit, the data in Figure 5 would not be expected to apply.

Aluminum Coatings

The discussion up to this point has been confined to corrosion rate measurements which merely reflect metal loss. However, an equally serious problem is the *scale* which results from corrosion. Even at relatively low corrosion rates, excessive amounts of iron sulfide scale may form on carbon and low chromium steels. Scale formation can be minimized by reducing the hydrogen sulfide concentration in the process streams. Where this cannot be done economically, the use of chromium-nickel alloys may be practical. Another way to protect steels from scaling is by aluminizing. Consequently, aluminum coated specimens were included in the TCR test racks.

Most of the test racks in the TCR units contained

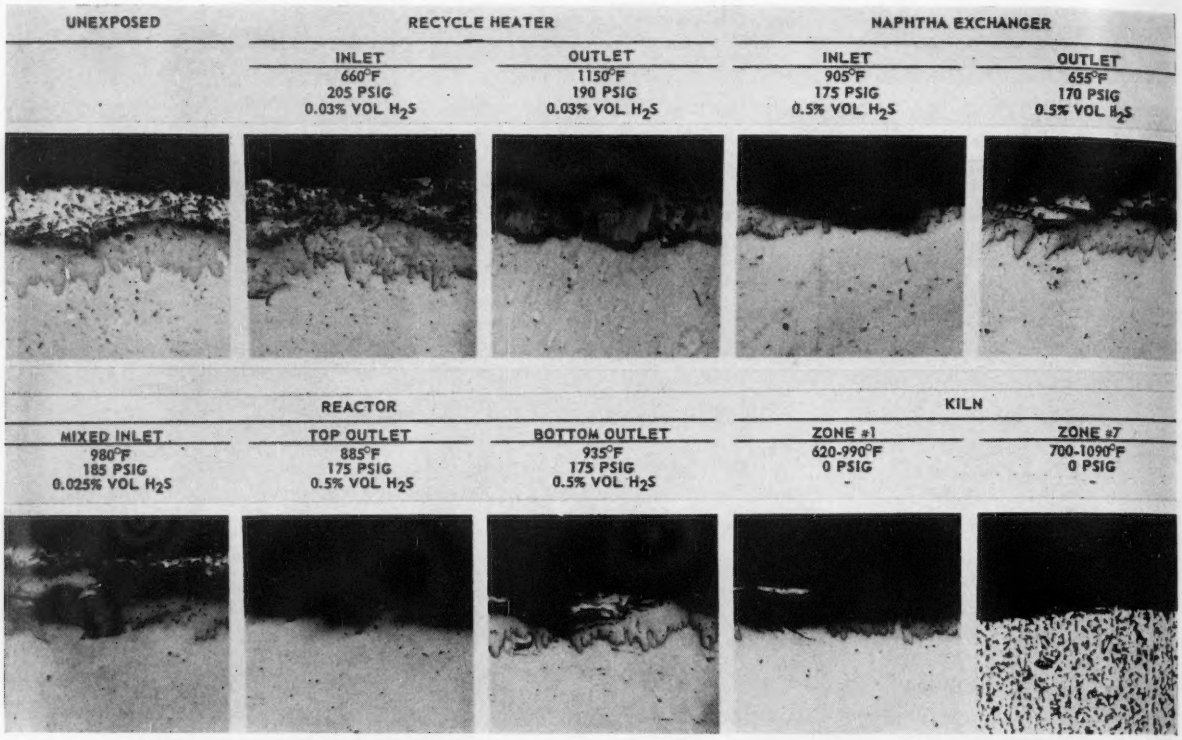

Figure 8—Photomicrographs of hot-dip aluminized specimens exposed for 55 days in Torrance TCR unit. 76X, unetched. (Lower right specimen same magnification, nital etch.)

two types of aluminum coated specimens. One was calorized (diffused aluminum coating) ASTM A-285-C carbon steel and the other type was hot-dip aluminized carbon steel (AISI 1020). There are other methods of aluminizing but the TCR tests were limited to these two types which were most readily available. For the purpose of testing these coatings, a carbon steel base was considered acceptable. But carbon steel, even when aluminized, is not considered suitable for high temperature or hydrogen service. A low chromium steel base material is preferred for protection against high temperature and hydrogen attack.

Tests on Calorized Steel

Figure 6 contains photomicrographs of calorized test specimens exposed at six different locations in the Torrance TCR unit for 55 days. Inasmuch as some of the unexposed specimens showed cracks in the brittle aluminum-diffused zone, it is possible that the cracks in the exposed specimens were present before the test. None of the cracks originating at the surface extend to the base metal or appear to contain any corrosion products. No significant decrease in the calorized area was noted. For these reasons, it is felt that calorized coatings can give satisfactory service under all the test conditions reported.

The dark line on the micrograph, slightly above the base metal, for the coupon exposed at the bottom reactor outlet appears to be a needle-like crystalline structure (probably an iron-aluminum intermetallic compound). Such an area has shown up in most calorized specimens exposed in the laboratory to hydrogen-hydrogen sulfide atmospheres at high temperature. Several other micrographs in Figure 6 indicate that such an area may be forming.

Photomicrographs of calorized carbon steel specimens exposed at four locations for 29 days in the Beaumont TCR unit are shown in Figure 7. None of these specimens failed at the test conditions.

As mentioned earlier, all the hot, low chromium steel transfer lines of the Torrance TCR unit were removed, cleaned, and calorized before the unit was put back on-stream. After this 55-day test period, the calorized lines appeared to be in excellent condition. Only a few small areas failed to protect against corrosion attack. After more than 200 days of operation, most of the calorizing was still providing adequate protection, but more localized failures have been noted while the older scaled areas have grown somewhat larger. These localized failures may be caused either by incomplete removal of corrosion products prior to calorizing or by erosion by catalyst fines.

Tests on Hot-Dip Aluminized Steel

Photomicrographs of hot-dip aluminized carbon steel are shown in Figure 8 after 55 days exposure in the Torrance TCR unit and in Figure 9 after 29 days in the Beaumont unit. The micrograph for the unexposed specimen clearly shows the aluminum overlay and the bond layer which contains 12 percent silicon-aluminum.

Since these tests have been completed, it has been

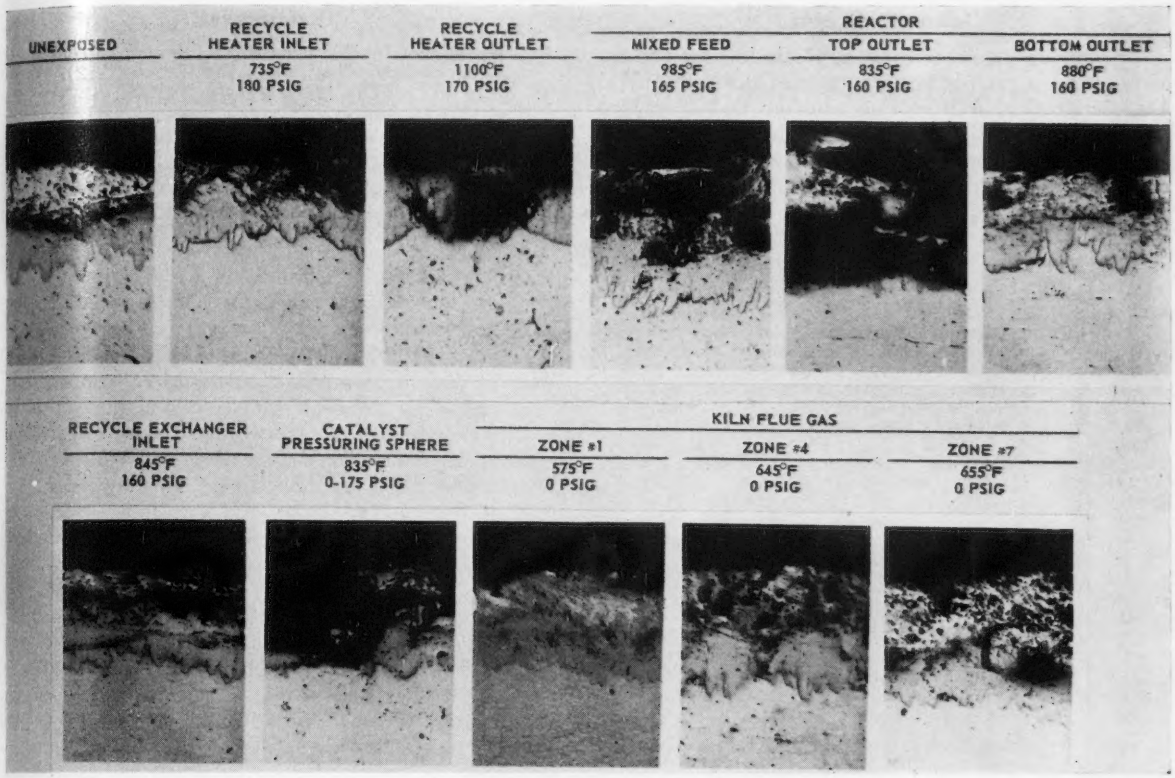

Figure 9—Photomicrographs of hot-dip aluminized carbon steel specimens exposed for 29 days in Beaumont TCR unit. Recycle gas averaged 0.009 percent hydrogen sulfide by volume. 77X, unetched.

learned that the supplier no longer recommends this type of coating for high temperature hydrogen-hydrogen sulfide service. None of these specimens were given a heat-diffusion treat prior to the test. The silicon bond is a deterrent to diffusion. None of the test conditions produced a significant amount of aluminum diffusion. A possible exception might be in the recycle heater outlet, Figure 8, where the coupon was exposed at 1150 F for 55 days. However, the coating on parts of this specimen was no longer tightly bonded. In the same figure, the etched specimen from kiln zone number 7, which was subjected to temperatures of 700 to 1090 F, shows complete loss of aluminum and no diffusion.

Because weight loss measurements would not be accurate for coated specimens, metallographic examinations were relied on for evaluation. In the authors' opinion, any appreciable disappearance of overlay or bond constitutes a failure. Using this as a basis, hot-dip aluminum coatings afforded satisfactory protection only at the lower test temperatures. The data, however, are not complete enough to establish a definite temperature limit.

Aluminizing, like the other control methods, has its limitations. The coating must be bonded to the base metal and must adhere under all normal exposure conditions of the coated equipment. Any satisfactory coating must be continuous or the exposed base metal will be vulnerable to scaling attack. For this reason, proper surface preparation is very important.

From the test results described, diffusion of the coating produces the best bond. Diffusion, however, requires relatively high temperature. In addition, application methods often have size and shape limitations. These factors must be considered before applying aluminum coatings in the field. It also is worth remembering that the coated test coupons were prepared under near ideal conditions.

Summary

Test results obtained in two commercial TCR units qualitatively confirm laboratory corrosion tests in hydrogen-hydrogen sulfide atmospheres. The data show that both temperature and hydrogen sulfide concentration are basic variables in high temperature hydrogen sulfide corrosion. Metal loss data from test coupons exposed in the field rated the corrosion resistance of the common alloys in the same order as laboratory tests.

Calorizing carbon steel test coupons provided protection from sulfide corrosion attack at all test locations in two TCR units. Hot-dip aluminum processing with an aluminum-silicon bond layer provided protection only at the lower temperatures. Calorizing of commercial equipment has been successful in minimizing hydrogen sulfide scaling.

Acknowledgment

The authors express their appreciation for the assistance given on this work by the staffs of the General Petroleum Corporation Laboratories and Torrance Refinery, Magnolia Petroleum Company Beaumont Refinery, and Socony Mobil Laboratories. Special thanks is extended to J. E. Prior who conducted the metallographic examinations.

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A Technical Note

Recent Navy Experience with Saran and Vinyl Coatings*

By W. W. CRANMER*

Abstract

The U. S. Navy has made extensive use in submarine tanks and in gasoline cargo tanks of tankers of a vinylidene chloride-acrylonitrile copolymer lining. It was found that the use of the material was justified in cases where a heavy duty coating resistant to fuels and salt water was necessary and short periods of moderately elevated temperatures were to be encountered. In addition to reducing corrosion it was found that use of the coating simplified the cleaning of tanks.

Results of the use of vinyl paints on U. S. Navy ships are reported. It was found that the vinyl system was sufficiently superior to the cold plastic paints in corrosion resistance to justify its use. It was found also that the vinyls gave a performance at least equal to the average obtained previously with hot plastic. The tough film of the vinyls did not check or embrittle. In view of the fact the film was still tough and adherent after two years' service it was concluded that touch-up rather than complete removal and renewal was feasible.

Introduction

A VINYLIDENE chloride-acrylonitrile copolymer lining dispersed in methyl ethyl ketone and pigmented white or orange has been used since 1948 on certain U. S. Navy submarine fuel and ballast tanks[1] and since 1953 on nearly all tanks in submarines. This coating is also being used on gasoline cargo tanks of tankers. Navy vinyl paint systems, including a wash primer whose essential components are polyvinyl butyral resin, basic zinc chromate and phosphoric acid, are now used on galvanized steel and aluminum weather decks, deck supporting shells, conning tower fairwaters and associated structures on submarines.

Concurrent (1949) with trials of vinyl paints on topside areas of submarines a vinyl antifouling paint system was tested on the underwater hull of a submarine. This trial consisted of a test patch of about 300 square feet between bilge keels. It remained in excellent condition for 22 months, outlasting two applications of standard cold plastic paint. This trial indicated that submarine bottoms once coated with the vinyl antifouling system could be maintained indefinitely by touching up corroded areas and reapplying a coat of antifouling paint at regular docking periods.

Conclusions from Tests on Saran

The current situation with respect to the vinylidene chloride-acrylonitrile copolymer (Saran) is as follows:

1. Saran coated submarine ballast tanks usually require about 1 to 2 percent and never more than 5 percent touch-up at regular overhaul periods.
2. Longest service period on gasoline cargo tanks known to date is about five years. It was reported that the coating had deteriorated on about 10 percent of the tank surface.
3. The author's review of the records on 16 ships, (not known to be representative examples) shows that 15 of the ships report Saran to be in excellent condition for periods ranging from 10 to 30 months. One reported 35 percent rusting after 19 months, a failure that could not be explained.
4. Present evidence indicates that once a tank has been cleaned by abrasive blasting and properly coated with Saran there will be sufficiently long service to warrant the coating cost.
5. The author has information on a group of 32 of the 200 Navy tank cars lined with Saran in 1950. After 4½ years carrying aviation gasoline, jet fuel and lubricating oil, 24 of the linings were reported in excellent condition and the remaining eight showed small spots directly under the dome where peeling had occurred.
6. Saran used in trimming and heeling tanks of ice-breaker type ships has remained in good condition during at least six winter operation periods.

In summary, service experience has justified the use of Saran wherever a heavy duty coating resistant to fuels and salt water is necessary and short periods of moderately elevated temperature are encountered. Its use has eliminated costly corrosion and has greatly reduced the need for frequent removal of sludge from tanks. Cleaning of tanks is easier also.

Experience With Vinyl Paints

Trials of vinyl paints conducted about the same time as the 1949 tests on submarines provided convincing evidence that the vinyl system was sufficiently superior to the cold plastic paints in corrosion resistance to justify its use, especially because there was the possibility the previous practice of blasting and completely repainting about once a year could be eliminated.

Black antifouling vinyls used on submarines proved to be less efficient against tubeworms and barnacles than red vinyl antifouling paint. When vinyl bottom paint systems were approved in November, 1953 for all submarines, the use of black paint was reduced to the minimum essential for camouflage.

During late 1954 and early 1955 the author's ob-

★A paper presented at a meeting of Northeast Region, National Association of Corrosion Engineers, May 9-11, 1955, New York, N. Y. This condensation was prepared by *Corrosion* from a version published in *American Paint J.*, **39**, No. 40, 20 (1955) June.

• Industrial Test Laboratory, U. S. Naval Shipyard, Philadelphia, Pa.

servation of five submarines which had received routine vinyl bottom paint jobs showed four were satisfactory and one a failure. The failure resulted because after application of the wash primer the ship was inadvertently washed down with salt water and the subsequent coats of paint were applied over this salt scum.

Other activities involving vinyl systems are as follows:

1. An effort is being made to reduce repainting to a minimum, emphasizing the maximum saving but highlighting any weaknesses in antifouling efficiency.
2. Starting in 1951 and continuing to the present, trials of vinyl bottom paints on 50 ships have been conducted. Some had bottoms painted completely with vinyls while others had bottoms divided into quadrants with opposing quadrants painted variously with vinyls or standard hot plastic paint.
3. Painting was done only as required by scheduled overhauls and at minimum extra cost except for test supervisions, reporting and inspection.

Results of the comparisons between the vinyl and hot plastic system are as follows:

1. On 42 ships painted in quadrants, 15 showed equal performance; 11 poorer and 16 better. The conclusion to be drawn is that the vinyls provide performance at least equal to the average previously obtained with hot plastic.
2. Based on evidence to date it is predicted that if all surface craft were painted with vinyl antifouling paint, 40 percent would show not more than 5 percent failure after 25 months; 35 percent would show not more than 10 percent failure after 23 months; 20 percent would show not more than 20 percent failure after 23 months and the remaining 5 percent could be expected to show failure by fouling in excess of 50 percent but less than 10 percent corrosion or film failure after 23 months.

Vinyl did not seem to suffer as a result of lack of applicators' familiarity with it versus hot plastic in the tests surveyed. Vinyl systems, including wash primer, anticorrosive and antifouling, averaged 10 mils in thickness while hot plastic was applied to a minimum of 30 mils.

Conclusions

The tough film of the vinyls did not check or embrittle. In view of the fact that the film was still tough and adherent after two years' service it was concluded that touch-up, rather than complete removal and renewal was feasible. This has been accomplished satisfactorily on some ships, with some evidence that indefinite maintenance is possible using spot touch-up plus additional coats of antifouling paint.

The Navy's experience indicates that both Saran and vinyl resins are supplying better answers to corrosion problems than were attainable previously.

Note: Opinions expressed in this article are those of the writer and do not represent the opinion of the Department of the Navy. Their publication is in no way binding upon any governmental agency.

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Any discussions of this article not published above will appear in the June, 1956 issue.

TECHNICAL PAPERS ON CORROSION WELCOMED

Authors of technical papers on corrosion are invited to submit them for review without invitation to the Editor of Corrosion. Write for "Guide for the Preparation and Presentation of Papers" sent free on request to prospective authors.

Corrosion Mitigation in a Metropolitan Area*

By M. C. MILLER*

Abstract

The corrosion mitigation of cable sheaths and other underground metallic structures in a metropolitan area involves many problems not encountered in the protection of cross-country cables and pipe lines. It is difficult for any one operator to apply protection to small section of his system or the entire system without increasing corrosion on other systems in the same area.

A description is given of how Miami utility companies participated jointly in the designing and installation of a cathodic protection system. Purpose of the project was to provide protection to all metallic structures in a certain downtown area. Eleven 50-ampere rectifiers were installed at selected locations throughout the area.

The selecting of reference electrode locations is discussed in detail. Other topics considered include cathodic protection design factors, tests made to determine need for resistance bonds, changes in construction practice, use of magnesium anodes and cost of installing cathodic protection.

After eight years time the Miami cooperative corrosion control program was found to have provided good protection to electric and gas and communication systems. Corrosion failures on protected communication system cables were found to be almost nonexistent. Corrosion failures on electric cable sheaths were found to have dropped to one per year.

Introduction

CORROSION MITIGATION in metropolitan areas involves many problems not encountered in the protection of cross-country pipe lines and cables. For well-coated pipe lines and cables, sections of which can be electrically insulated from other sections and structures, the application of cathodic protection utilizing small rectifiers or galvanic anodes presents no special problems. Where bare pipe lines, cable sheaths and other structures need protection, the problems increase in proportion to the size of the city. It becomes increasingly difficult for the operator of any one facility to apply protection to small sections of his system or the entire system without increasing corrosion on other systems in the same area.

In many metropolitan areas the need for protection many times is felt by one of the utilities a number of years before corrosion becomes serious on other systems. In Houston, it was on the gas distribution system that corrosion first became serious. In Norfolk, Virginia, the telephone system cables were the first to need protection. In Miami, Florida, the corrosion became serious on the electric system cables, while corrosion failures on the telephone system cables and on the gas and water systems were considered minor.

The operator of the system first to require extensive corrosion mitigation may suggest a cooperative installation of protective measures, but other operators may find little to justify expenditure of much money. The tendency therefore is for the first operator to protect his own system as best he can. In a metropolitan area his progress at best is likely to be slow and expensive.

In Jackson, Mississippi, a utility operating the gas distribution system found corrosion failure becoming serious. Some form of protection was needed but the application of cathodic protection was made more difficult because of the previous installation of rectifiers on the telephone cable system. A few years later, corrosion failures became serious on the electric cable system. Looking backward, it now appears that for a relatively large section of Jackson the application of joint or cooperative corrosion control measures would have been the ideal solution. When corrosion failures become serious on an extensive electric cable system in a metropolitan area it is usually impracticable to apply cathodic protection to the electric cable system only.

Cooperative Installation

The methods used to reduce corrosion failures on underground structures in the business district of Miami, Florida, and the results obtained with the protective installations may be of interest to persons who operate and maintain underground systems in metropolitan areas.

This major corrosion control program has been in effect for eight years. Corrosion engineers of the electric and gas systems and communication systems report good results. Corrosion failures on electric cable sheaths are down to one per year. On the communication system cables in the area protected, corrosion failures are almost nonexistent.

Installation of the Miami cathodic protection system in 1947 was unique in at least one respect. In so far as is known to the author it was the only such installation in existence at that time in the United States where all utilities involved jointly planned, designed and installed an over-all cathodic protection installation to provide protection to all underground metallic structures in a large section of a metropolitan area. The area protected covers the entire business district of Miami as shown in Figure 1.

A brief resume of conditions that resulted in the decision to install joint protection is of interest as it could well apply to any area. The details of the installations would change, but the division of costs, methods of testing, and operation and maintenance procedures would be applicable to other locations. It would be difficult to evaluate the results in terms of dollars saved; the benefits must be based on opinions of the operators.

The need for some form of corrosion mitigation on the underground electric cable system of Florida

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* Electrical engineer, Ebasco Services Incorporated, New York, N. Y.

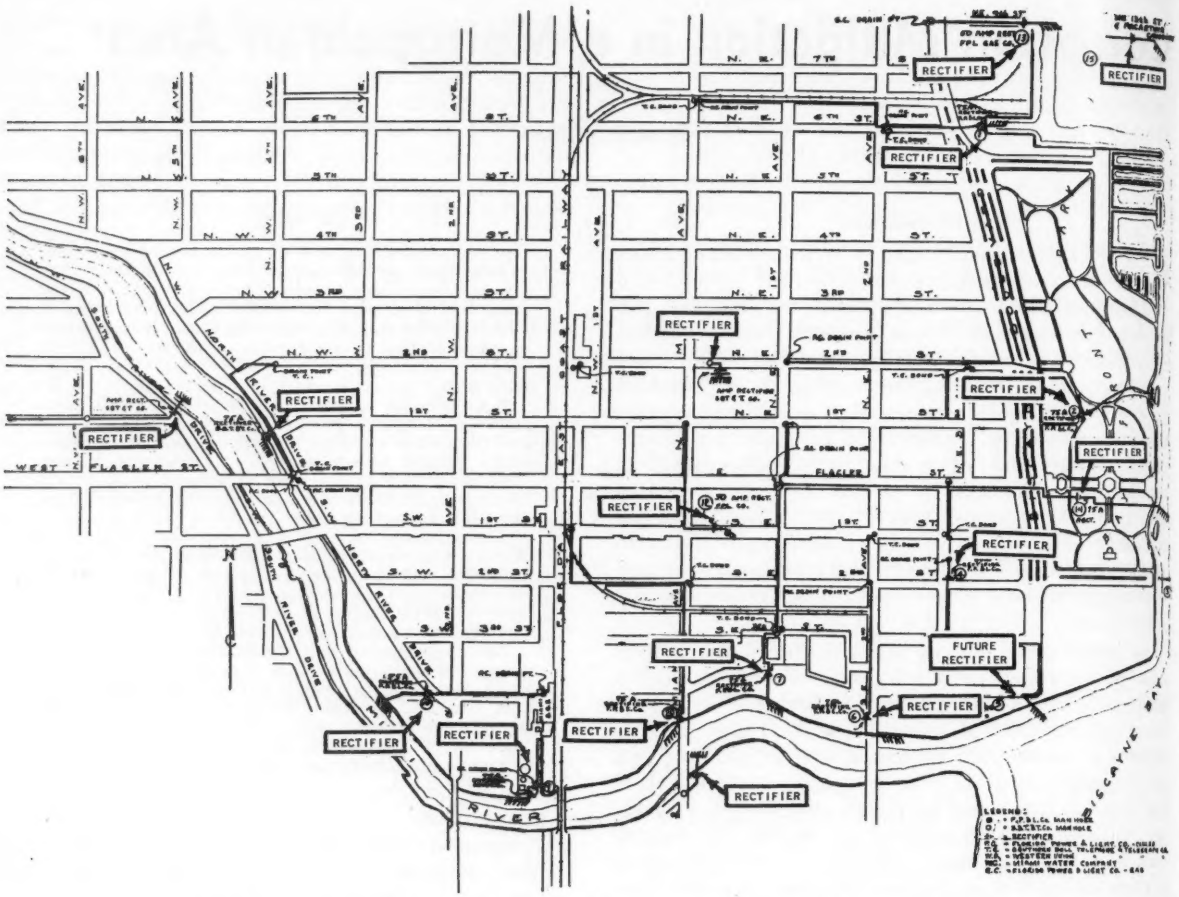

Figure 1—Map showing installation of rectifiers for cathodic protection for Miami network area.

Power & Light Company became apparent as the rate of cable failures increased rapidly. Ebasco Services Incorporated was requested to send a corrosion engineer to investigate the causes of failures and to suggest remedial measures.

In addition to the electric cable system, Florida Power & Light Company owns and operates the gas distribution system. Corrosion on gas mains and services was not considered to be serious. The water system is municipally owned and operated. Corrosion on this system was not rapid. The Southern Bell Telephone and Telegraph Company and the Western Union Telegraph Company had installed a small amount of forced drainage from central-station batteries. Corrosion failures of their cables in the business district of Miami were minor.

A review of conditions existing a few years previously indicated that corrosion of cables and piping systems in the business district had been mitigated by drainage of the street railway return current. The last street railway system had been out of service about seven years before corrosion failures on the electric cable system became numerous.

The major causes of corrosion failures on electric cables were definitely traced to galvanic corrosion resulting principally from extensive use of dissimilar metals. In addition to the relatively large amounts of bare copper being used for neutrals (which in the past had been an almost universal practice), the cable sheaths were solidly connected to an electric-generating station low-resistance bare-copper grounding system which included metal plates buried in coke.

To make conditions more corrosive, many of the bare copper neutrals were in duct lines that were flooded by tide waters of varying salt content. Also, as is usual practice throughout the country, the cable system sheaths, neutrals and grounds were solidly connected to the water system, gas system, building foundations, water well casings and other metal structures. All these metals formed a huge galvanic battery.

Only a brief economic study of comparative methods of reducing corrosion was necessary to show that a system of cathodic protection was desirable. It was apparent, also, that changes in design and construction practices were needed.

As corrosion failures up to that time appeared to be serious only on the power system network of cables, consideration was at first given to electrically insulating the electric cable-sheath system from all other underground structures, and installing cathodic protection by use of rectifiers with ground beds in river, bay, and duct lines, and by installing galvanic anodes in manholes.

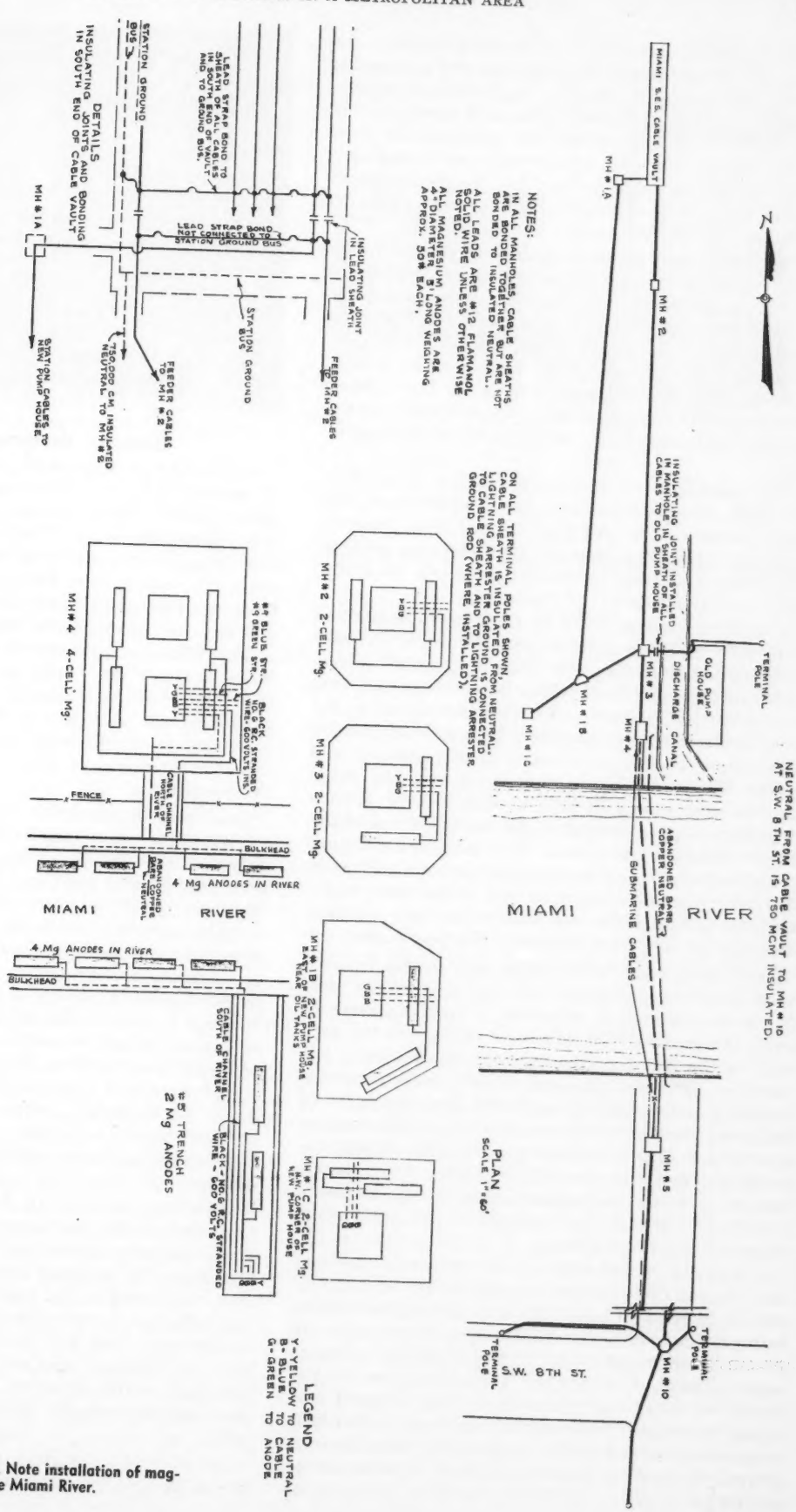
NOTES:
IN ALL MANHOLES, CABLE SHEATHS ARE BONDED TOGETHER BUT ARE NOT BONDED TO INSULATED NEUTRAL.
ALL LEADS ARE #12 FLAMANOL SOLID WIRE UNLESS OTHERWISE NOTED.
ALL MAGNESIUM ANODES ARE APPROX. 50# EACH.
ON ALL TERMINAL POLES SHOWN, CABLE SHEATH IS INSULATED FROM NEUTRAL. LIGHTNING ARRESTER GROUND IS CONNECTED TO CABLE SHEATH AND TO LIGHTNING ARRESTER GROUND ROD (WHERE INSTALLED).
DETAILS INSULATING JOINTS AND BONDING IN SOUTH END OF CABLE VAULT
STATION GROUND BUS
LEAD STRAP BOND TO SHEATH OF ALL CABLES IN SOUTH END OF VAULT AND TO GROUND BUS.
LEAD STRAP BOND NOT CONNECTED TO STATION GROUND BUS
INSULATING JOINT IN LEAD SHEATH
MH #1A
STATION GROUND BUS
750,000 CM. INSULATED NEUTRAL TO MH #2
FEEDER CABLES TO MH #2
FEEDER CABLES FROM MH #2
STATION CABLES TO NEW PUMP HOUSE
MIAMI S.E.S. CABLE VAULT
MH #1A
MH #2
MH #1B
MH #3
MH #4
MH #10
INSULATING JOINT INSTALLED IN SHEATH OF ALL CABLES TO OLD PUMP HOUSE
OLD PUMP HOUSE
DISCHARGE CANAL
TERMINAL POLE
NEUTRAL FROM CABLE VAULT TO MH # 10 AT S.W. 8TH ST. IS 750 MCM INSULATED.
MH # 2 2-CELL Mg.
MH # 3 2-CELL Mg.
MH # 4 4-CELL Mg.
#8 BLUE STR. #8 GREEN STR.
BLACK #6 R.C. STRANDED WIRE-600 VOLTS INS.
CABLE CHANNEL UNDER RIVER
FENCE
BULKHEAD
ABANDONED BARE COPPER NEUTRAL
4 Mg ANODES IN RIVER
MIAMI
RIVER
SUBMARINE CABLES
ABANDONED BARE COPPER NEUTRAL
MH # 1B 2-CELL Mg. NEAR OIL TANKS
MH # 1C 2-CELL Mg. NEW PUMP HOUSE
#5 TRENCH 2 Mg ANODES
CABLES IN TRENCH SOUTH OF RIVER
BLACK - #6 R.C. STRANDED WIRE - 600 VOLTS
PLAN
SCALE 1"=80'
S.W. 8TH ST.
LEGEND
Y - YELLOW TO NEUTRAL
B - BLUE TO CABLE
G - GREEN TO ANODE

Figure 2—Miami electric distribution. Note installation of magnesium anodes and in the Miami River.

This method, however, was deemed entirely impractical. While it may be practical and reasonable in cost to electrically insulate communication-cable sheaths or gas-distribution mains and services from all other metallic structures, this could not be done in this case because the cable sheaths were grounded to aid in clearing cable faults. Also, the sheaths carry part of the normal unbalance load current in parallel with grounds and neutrals.

For safety reasons, lead sheaths of service cables were bonded to conduit (if metal) and to customers' wiring-system neutral, to power system neutral at almost every manhole, and to water systems. They were bonded indirectly to all other metallic structures including building foundations, and, as realized later, to many deep well casings. It long has been almost universal practice and considered a desirable practice to bond cable sheath to all metal structures within reach.

The possibility of electrically insulating the electric cable sheaths was discarded at once. Even if it were practical, the problems would then arise of applying cathodic protection over the area without possibility of causing corrosion damage on the multitude of other structures in the area.

Consideration was given to applying protection to "hot spots" utilizing galvanic anodes in manholes and other suitable locations. To obtain quick relief in one duct run that contained feeder cables only and that was somewhat isolated from other structures in the area, protection was provided by galvanic anodes. Magnesium anodes were installed in manholes and in the Miami River. In this cable run the cable sheaths were insulated from station ground, from a large bare copper neutral in the duct line, and from the overhead neutral system. This is shown in Figure 2. Although corrosion failures had become serious in this cable run and sections of the sheath were badly corroded and pitted, no corrosion failure has occurred since the anodes were installed nine years ago.

Tests were made with magnesium anodes in manholes in various sections of the business district area. A few were installed to provide a small measure of quick temporary relief. However, except in the area close to the Biscayne Bay and the Miami River, the water in the manholes was mostly high-resistivity surface water and many manholes were dry most of the time. Even where the magnesium anodes were in manholes with low-resistivity water, the output was small and the effect usually negligible more than a few feet outside the manhole. Most of the corrosion failures in the past had occurred in the ducts some distance from the manholes.

It was obvious that a cathodic protection system with considerable current output would be needed; also, that only through the use of rectifiers could sufficient current and adequate spread of current be obtained. Although only the power-system cables were in need of protection, it was apparent that it would be necessary to leave all cable sheaths and piping systems interconnected and tied to building foundations, water wells and other miscellaneous structures, and to provide at least a measure of protection to all.

It was believed, however, that it would be possible and practical to design the cathodic protection installation to force the electric-cable sheaths to collect a large percentage of the current. This was possible because the gas and water systems were mostly of cast-iron pipe. Also, the Southern Bell Telephone and Telegraph Company had insulated most of their cable sheaths from other structures in the area.

A meeting to discuss the situation and possible solution was attended by representatives of the Florida Power & Light Company, Southern Bell Telephone and Telegraph Company, Western Union Telegraph Company and City of Miami Water Department. The result was full cooperation by these companies throughout the design and installation period, and during subsequent testing, operation and maintenance of the protective system.

Cathodic Protection Design

Soil resistivity tests indicated that the installation of ground beds in the business district would be impracticable. Much of the subsurface consists of oolite limestone rock. The water in Biscayne Bay and Miami River has low resistance, approaching sea water, and is ideal for low-cost, efficient ground beds. Also locations could be found along the river and bay for above-ground rectifier installations.

The difficulty, however, was that the cable sheaths were on the fringe of the area to be protected and their resistance was too high to provide for suitable spread of the cathodic protection current. It was necessary to install large insulated negative return cables from points of heavy cable concentrations to the rectifiers.

It seemed impractical to conduct preliminary tests to determine what magnitude of current would be required. The number of possible locations for rectifiers and ground beds and the pratical capacity of rectifiers largely dictated the design of the initial installation, which included ten 50-ampere rectifiers or a total of 500-ampere output capacity. Locations of rectifiers are shown in Figure 1. The type of rectifiers used are shown in Figure 3. Past experience on large systems indicated that at least this amount of current would be required. Plans were made to add additional rectifiers if needed. If current requirements were less than expected, the protected area would be extended or the output of one or more rectifiers would be reduced.

To some corrosion engineers, chief engineers, and management, this "cut-and-try" method may seem like poor engineering. In defense of this method one must realize that the cost of temporary installations and exhaustive testing necessary to determine with any degree of accuracy the current required, taking into consideration the polarization effects which are not fully felt for months, would be almost as great as the cost of the actual installation. It is contended that the selected method is the most economical approach in this situation, although it might not be good engineering for the usual pipe line or cable job.

Actually, the original estimate was not far off as can be seen from the fact that there now is a total

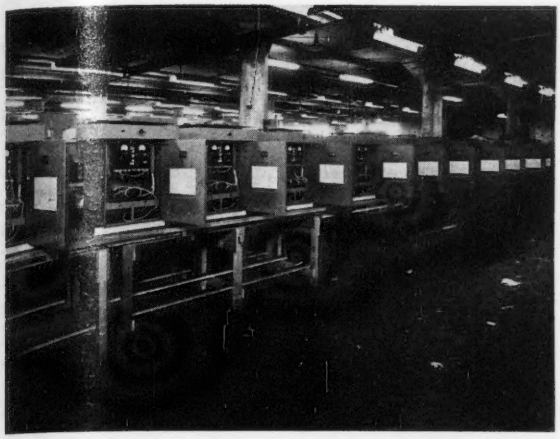

Figure 3—Fifty-ampere rectifiers for Miami cathodic protection installation.

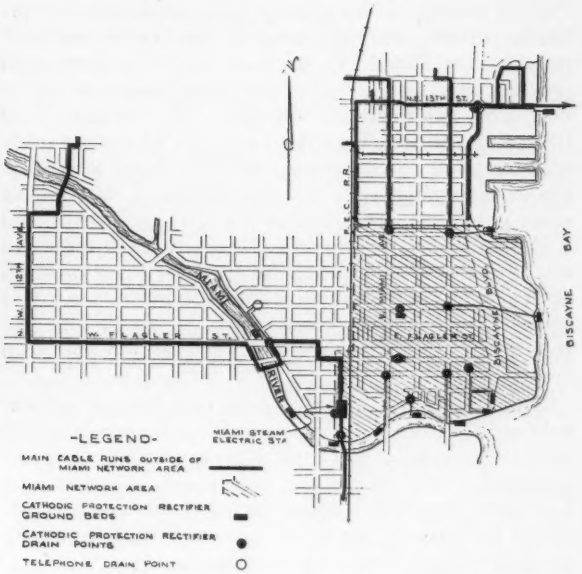

Figure 4—Map showing extension of cathodic protection in Miami.

of approximately 800 amperes of rectifier capacity installed and the protected area has been extended. In this connection a comparison may be made of Figures 1 and 4.

Initial tests made after energizing the rectifiers showed need for rectifiers in the center of the area, as was expected. The corrosion engineer of the Southern Bell Telephone and Telegraph Company suggested the use of an abandoned water well casing at the main central office located in the center of the area. A rectifier was installed in the electric transformer vault and the well casing used as a ground bed with good results. This led to a search for other abandoned water wells. Three were located at Burdin's Department Store, also close to the center of the area. A rectifier was installed in the transformer vault in that building. These made very low-cost installations. The well casings were deep and extended down into salt-water strata.

Subsequent tests showed a need for additional capacity at the northwest corner of the area, principally for the benefit of the telephone cables. Therefore, the Southern Bell Telephone and Telegraph Company supplied the rectifier installation at that location with the ground bed in the Miami River.

The Western Union Telegraph Company had a relatively small amount of cable in this area, which was being partially protected by current supplied from their office battery. This was disconnected and their cable connected to the network.

The gas piping system owned by the Florida Power and Light Company receives some degree of protection, although no attempt was made to provide complete protection. This attitude was taken because corrosion up to that time had been minor.

The water system, being tied in very solidly with the electric cable system, receives considerable protection; however, joints in the cast-iron mains limit the amount of current collection to a reasonable amount. As this was desirable to eliminate any possibility of causing corrosion on the water system, no attempt was made to determine what proportion of the total cathodic protection current was collected directly on the water system. The city water works engineer advised that their corrosion problems were minor. No attempt was made, therefore, to provide protection to the water system—only to avoid damage. The water works engineer was very cooperative in the planning, installation and testing the protective system.

Cost of Installation

The total cost of the engineering services and of the cathodic protection installation has been low—primarily because of the natural locations for low-cost ground beds, and the elimination of the preliminary current requirement tests and temporary installations. The annual operation and maintenance costs to date have been low, but no figures are readily available.

High Points in Testing

All testing subsequent to installation of the first rectifiers was carried on cooperatively. The Southern Bell Telephone and Telegraph Company supplied a control circuit from their central office to each rectifier with a relay at each rectifier to facilitate turning all rectifiers on and off. A motor-operated current interrupter was installed at the central office to turn all the rectifiers "on and off" on a definite cycle during the day while tests were being made. A circuit was provided from the central office in Miami to the control office in Miami Beach where it was connected to ground. It was extended to four or five locations in the protected area. This enabled measurement of the "change in potential" to remote earth, which was particularly helpful in analyzing structure-to-earth potentials with the usual reference electrode locations. Without this remote reference, it would have been difficult indeed to interpret some of the readings. Use of this reference made it possible to save considerable testing time.

Two testing crews usually were used, each covering a different part of the area. One crew was supplied by the Florida Power and Light Company and was accompanied by their corrosion engineer and a corrosion engineer and assistant of Southern Bell Telephone and Telegraph Company. The other crew was supplied by Southern Bell Telephone and Telegraph Company and was accompanied by one of their corrosion engineers and a Florida Power and Light Company engineer and helper. Each crew did all of the testing at each location in their area on both power and telephone cables. Potentials of cable systems were measured to earth, to water and gas piping, and to each other with rectifiers on and with rectifiers off.

This method of utilizing only one crew at a location reduced the blocking of traffic which was heavy at most locations. As far as was practicable, only one manhole at an intersection was opened at one time. Corrosion engineers representing both systems assisted in tests on both systems, and each company made the tests it believed necessary.

During this first phase of testing, representatives of Western Union Telegraph Company and of the water systems were not present. This was because those tests were designed primarily to determine the over-all degree of protection and whether or not additional bonds between telephone cables and power cables would be required. It was found that a few additional bonds, mostly near the tie-in point of the negative drain cables, were needed. These were installed and adjusted, mostly by the "cut-and-try" method.

The next step was for the Florida Power and Light Company engineers to conduct joint tests with representatives of the gas and water systems and to install resistance bonds where they were found to be desirable. The rectifiers were then left on full time for a few days to build up polarization, after which spot checks again were made without turning the rectifiers on and off.

It appeared that the average over-all shift of potential to earth was about .2 volt or more negative in the areas near the negative return tie-ins and as little as —.1 volt in some fringe areas. This was considered good.

Location of Reference Electrode

As usual, the question was raised of where to place the reference electrode with reference to the structures. The change in potential of the cable sheaths to far remote earth (Miami Beach) showed that with all rectifiers "on and off," the entire network was being changed by about half a volt. The difference in potential changes at various locations measured to remote was a measure only of the IR drop in the cable sheath system between those locations. Measurement of the earth potentials in the area, again to the remote ground, showed that the earth throughout the area was being raised and lowered in potential almost as much as the cable and piping systems.

Measurements of cable sheaths to reference electrodes in the manholes showed various results. Where the water in the manholes covered the cables the change in potential was very small (only a few millivolts) because the water in the manhole was changing in potential to remote earth almost as much as were the cable sheaths. The manhole walls, especially if made of reinforced concrete and located in dry high-resistance earth, tend to make the cable sheaths, bare neutral, metal hangers and the water in the manhole all one unit and all changing in potential to remote earth to almost the same extent. It was reasoned and substantiated by tests that under such a condition, galvanic corrosion of the lead sheaths connected to bare-copper neutrals in the manhole might be reduced but not necessarily stopped. Full protection in most of the manholes where the water was over the cables and neutrals could be obtained only by the use of galvanic anodes in the manhole.

Where the water in the manholes was below the cable sheaths and bare neutral, larger changes in potential were measured. The potential of the sheaths to electrode outside the manhole in the gutter, along the curb or wherever contact with earth or wet pavement could be made, showed much larger changes. Electrode-to-electrode measurements showed current flow toward the cables and pipe lines when the rectifiers were turned on.

Joint Tests to Determine Need for Resistance Bonds

In small areas where negative returns to rectifiers were connected to cable sheaths of electric cable system, it was found that the potential to earth of the telephone cable changed in a positive direction when the rectifiers were turned on. Resistance bonds were installed and adjusted to a value that resulted in a negative change in potential of the telephone system.

The cable system of the Western Union Telegraph Company was relatively small. It was connected to the electric cable system through a resistance bond; the Western Union Telegraph Company discontinued drainage from its station battery.

Subsequent to testing on the cable systems, joint tests were made on the high-pressure and low-pressure water systems. Because of the many connections between the electric cable sheaths, electric system neutral and the water system piping, the potential changes except near the drain points were in a negative direction and almost as great as the change of cable potentials. It was necessary to install a few resistance bonds near the drain points of the rectifiers.

Ownership

There is no practical method of determining what percentage of the total rectifier current output is collected by each system. The percentage of area of each system may have little relationship to the amount of current flow to each system. In dry duct lines, cable sheaths which usually have only a line contact with the duct may collect very little current. Bare copper neutrals located in flooded ducts or buried directly in earth probably will collect more current than would be indicated by the relative areas because of the more positive potential of the copper.

Sections of cast-iron piping will collect varying amounts of current depending upon distance from a tie-in with the electric cable system, resistance of joints and other factors.

There is as well no practical method of determining the economical benefits on each system. However, in Miami all parties involved seemed well pleased with the costs to them and the results obtained. The Florida Power and Light Company apparently realizes that the present system costs far less than any other method of corrosion mitigation they could have used. The Southern Bell Telephone and Telegraph Company is obtaining some protection throughout the area at the small cost of one rectifier at a location where one was needed for their under-river cable crossing. Their engineers realize fully that without this protection corrosion failures on their cable system might develop.

The city water works engineer is aware that considerable protection is being obtained on the water system mains and services. Although corrosion problems were small up to that time, this protection certainly will reduce corrosion and prolong life of the material involved.

Changes in Construction Practices

Subsequent to the installation of this cathodic protection system, new high-voltage cables installed by the Florida Power and Light Company in this area have been protected by a plastic or neoprene sheath over the lead sheath. This avoids increasing the amount of cathodic protection current required. Low-voltage secondary and service cables installed have been mostly rubber or plastic insulated. New copper neutrals installed are insulated with a plastic covering.

Summary

This cathodic protection system is a monument to the engineers who showed the best of cooperation in solving a serious corrosion problem for the benefit of all concerned. While the details are not applicable to any other city, the method of approach and method of sharing costs somewhat in proportion to the needs of each system, all through mutual cooperation and without the need of legal entanglements, could well be considered by engineers facing somewhat similar corrosion problems.

Two other cities are starting cooperative installations. In Norfolk, Virginia, corrosion control is needed by the telephone company. Two rectifiers have been installed with connections to telephone and electric cables and to water and gas piping. In a city in Louisiana, plans are being prepared for a joint cooperative system. It was initiated by the owner of the gas distribution system. Undoubtedly there are many others.

In many systems throughout the country, it was found that cooperative drainage systems were the only practical method of avoiding corrosion from stray railway current. Even so, many companies are finding it necessary for one reason or another to try "going it alone" in the installation of cathodic protection in metropolitan areas. Perhaps a closer look might show real benefits over a long period of time if cooperative installations were started.

Any discussions of this article not published above will appear in the June, 1956 issue.

DISCUSSIONS ON TECHNICAL ARTICLES ARE SOLICITED

Discussions on technical articles published in Corrosion will be accepted for review without invitation. Discussions must be constructive, accompanied by full substantiation of fact in the form of tables, graphs or other representative data and be submitted in three typewritten copies.

Authors of discussions are asked to supply one copy of figures suitable for reproduction and will be sent on request a copy of the NACE Outline for the Preparation and Presentation of Papers.

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An Application of Cathodic Protection To the Inside of a Tank*

By J. H. GRAVES

Abstract

A 10,000 barrel bolted tank was found to have developed active internal corrosion within an eight year period. The tank was then coated on inside bottom and two feet up on the shell with a coal tar product, and steam coils were installed. After 12 years' additional service it was found that four leaks had developed in the tank. It was again cleaned, the steam coils removed, and the tank visually inspected. Welded repairs were made to the tank and the coating was repaired. Four 9 pound magnesium anodes were installed at this time and 6 inches of water were placed in the tank to serve as electrolyte. Anodes were installed so that they could be inspected or replaced while the tank was in service; records were made of anode outputs, driving potential, anode efficiency and tank-to-electrolyte potential. Current outputs were restricted and the 9 pound anodes ultimately were replaced with 17 pound anodes.

A measured output of 666 ampere-hours/pound was obtained from one of the 9 pound anodes. It is calculated that four 17 pound anodes would last 3 to 4 years, with more than ample current when restricted with a 1 ohm resistor. Tank to electrolyte potential at the last reading measured —0.4 volts to iron reference electrode.

Control was obtained by utilizing a 5 foot x 7 foot test tank filled with one foot of electrolyte from the 10,000 barrel tank.

J. H. GRAVES—District engineer, Tidal Pipe Line Co., Joinerville, Texas. After receiving a BS in civil engineering from Oklahoma A and M College in 1935 he went to work with Tidal Pipe Line Co. where he has served in a number of engineering capacities. Mr. Graves has been active in pipe line corrosion mitigation since 1938. He is a member of NACE.

Introduction

INTERNAL CORROSION of a crude oil storage or working tank becomes a problem when corrosion penetrates the tank shell or bottom and the product contained begins a slow or fast exit from the tank.

Detection of internal tank bottom corrosion is made more complicated because of the fact that the product being handled comes from diverse sources. Most crude oils contain some water and sediment that will settle out at the first opportunity. Oil field brines and "basic sediment" contain chlorides, sulfates, carbonates, and in addition may contain acids, carbon dioxide, oxygen, and various bacteria.

In past years it has been the practice of the author's company to make monthly visual inspections for leaks on all crude oil tanks. At the time tanks were opened for cleaning or other purposes they were inspected inside if possible. Such visual inspections offer the surest means available for detecting active corrosion, but other means are being used now to detect corrosive conditions. In this way corrosive conditions can be corrected in some cases before repairs are necessary. A certain amount of corrosion control can be exercised while tanks are in service and the useful life of the tanks thereby prolonged.

The application of cathodic protection to the exterior tank bottom requires particular attention. The beneficial effects obtained will be reduced unless the internal tank bottom corrosion can be stopped or controlled.

Tank 612 is a 10,000 barrel bolted tank 55 feet in diameter and 24 feet high, located at the Tidal Pipe Line Company's Bradford Station in Rusk County, Texas. It was erected new in March 1931 at a cost of $5,375. The tank has been in East Texas Grade Crude service since that date. Because it is a station working tank it is frequently filled and emptied. Gradually there is an accumulation of water and basic sediment in the tank until eventually it becomes difficult to accurately gauge the contents. Eventually it becomes necessary to clean the tank.

Inside Tank Bottom Pitting

In 1939, during the second cleaning of Tank 612, pitting and other evidence of corrosion was observed on the inside tank bottom and on the shell confined to the area filled with basic sediment and water. Consequently, the tank was thoroughly cleaned and the bottom and lower two feet of the shell coated with a coal tar product at a cost of $482. The bottom coating was weighted with sand and placed to a depth of one quarter inch. Also 652 feet of 2 inch pipe and 32 - 2 inch ells were installed as steam coils 6 inches from bottom. They were supported by 51 pieces of 4 inch pipe welded to 8 inch x 8 inch x ⅛ inch steel plates. The tank bottom was 10 gauge steel 0.134 inch thick, while the bottom ring of the shell was 7 gauge steel 0.180 inch thick. When a tank sheet was removed the bottom coating was made easy to clean but visual inspection of the tank bottom was made virtually impossible.

On October 7, 1951, a local tank repair crew patched three holes in the bend in the bottom end of some of the first ring shell sheets. This initial repair bill was $37.50. In 20 years service, corrosion had penetrated 7 gauge steel (an average corrosion rate of just under 9 mils per year). Product loss was

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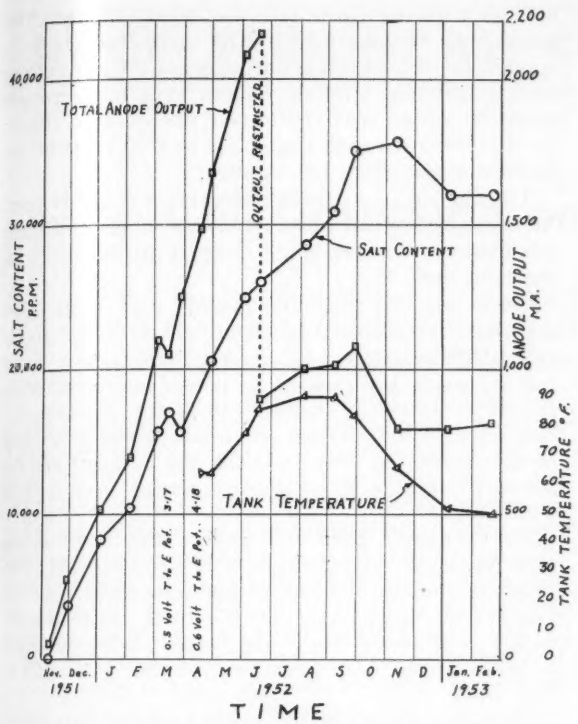

Figure 1—Graph showing time versus total anode output, chloride content and tank temperature for Tank 612 Bradford.

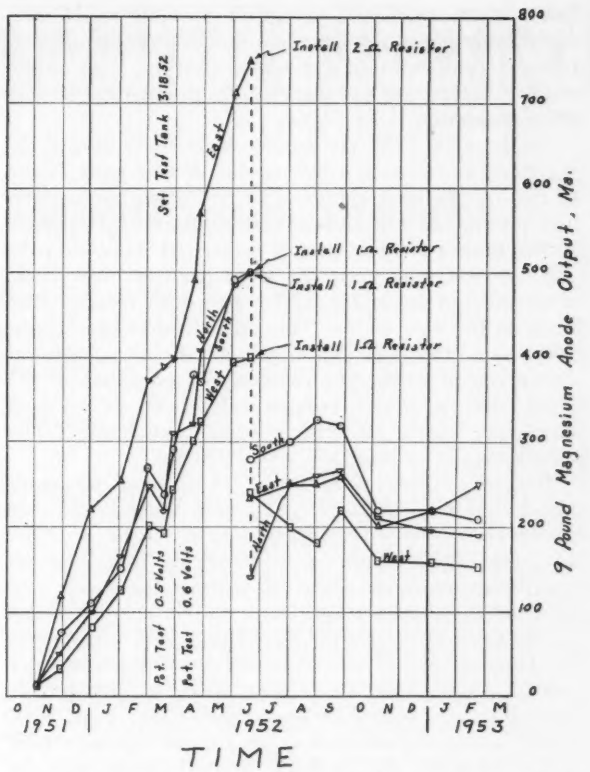

Figure 2—Graph showing time versus anode output for Tank 612 Bradford.

negligible and the tank could not be removed from service for cleaning at that time.

A month later oil began coming from under Tank 612. The tank was promptly cleaned of basic sediment and water, the steam coils were removed and the tank was visually inspected. A hole was found in the bottom where internal corrosion had penetrated the 0.134 inch steel at an average rate of 6 mils per year. The repair job cost $560, and included removing eight sheets for repair by welding. Numerous other spots were welded in place on the bottom and about four inches up on the shell. The hole in the tank bottom occurred where a steam coil support had rested and pushed the bottom coating from the steel in what appeared to be an eight inch square area. Observation of corrosion damage inside this tank prompted installation of cathodic protection to the inside bottom of the tank to match the outside cathodic protection.

Magnesium Anodes

The coal tar coating was not entirely removed from the floor of the tank but all visible defects were repaired by cleaning, priming and applying hot coal tar pipe line coating. The shell was scraped clean for inspection and again coated to the two foot level with a brushable coal tar product. Four, nine pound magnesium anodes were placed inside the tank. No. 12 TW copper lead wires were run from the anodes to the roof of the tank through an insulated bolt near each of the four roof openings. A suitable shunt of one thousandth ohm resistance was permanently installed to carry the current from the insulated bolt back to the tank shell and bottom.

The anodes themselves were insulated from the bottom by pouring three gallons of clean sand inside a 30 inch circle of coal tar where each anode was to be placed. After this the insulated lead wire was wrapped twice around the anode. The regular nine pound anode as furnished with ten foot lead for cathodic protection of pipe lines was used for the following reasons:

1. The anodes were readily available in stock.
2. Cost per pound of magnesium would be low.
3. The anodes could be inserted through existing tank openings.
4. The anodes were light enough to be removed for inspection.

In order to have an electrolyte to carry the protective current to the inside tank bottom and lower portion of the shell, water was placed in the tank to a sufficient depth to cover all four anodes. A depth of six inches was required for the initial installation. This drinking quality water contained 236 ppm total solids of which 58 ppm was chlorides, 40 ppm sulfates and 10 ppm iron; the pH was 8.3. The initial total anode output was 45 ma on November 5, 1951. On November 30, 1951, this output had increased to 272 ma and the chloride content of the water was 3,849 ppm. At this time a great difference was noted in the individual anode outputs, which varied from 30 to 120 ma each. It was noted that the east anode located ten feet from the tank shell had the high output while the opposite anode four feet from the shell had the

low output. During a period of 14 months, 16 sets of measurements were made of anode output and salt content (chloride) of the water bottom. The anode output varied almost directly in proportion to the chloride content (see Figure 1).

On June 18, 1952, the anodes were delivering 2,150 ma and the chloride content was 26,000 ppm. Some of the anodes were removed for weighing, inspection and photographing and then they were again placed in the tank and their output restricted. One ohm, 10 watt wire wound resistors were used on the south, west and north anodes, and a two ohm resistor was used on the east anode. This stabilized anode output was near 1,000 ma. On March 17, 1952, a potential check inside Tank 612 disclosed a potential of 0.5 volts tank to water bottom referenced to an iron electrode, which was nearly twice that desired. The anode output in this case was 1,040 ma.

Figure 1 shows the results of plotting measurements against time of total anode output, chloride content, and tank temperature. The break in curve of total anode output was caused by installing resistors in the anode circuit to restrict the anode output and thereby increase anode life. The small break in the total anode output curve probably was caused by temperature. There is good correlation between anode output and tank temperature within the observed range of 50 to 90 degrees F. East Texas Field Woodbine produced salt water contains about 40,000 ppm chlorides which might be an upper limit for chlorides to be expected in Tank 612.

Figure 2 shows the result of plotting individual anode outputs against time. The sharp break again is caused by restricting the anode outputs. Note the higher output of the east anode installed 10 feet from the shell and the lower output of the other anodes before resistors were installed. Restricted outputs indicate that about a two year life can be expected from the nine pound magnesium anodes. Mutual interference between the four anodes is very marked, indicating complete coverage of the tank bottom surface.

Test Tank

A test tank was installed on March 18, 1952, shortly after the tank to electrode potential was measured 0.5 volts and anode life expectancy was growing short. The tank was constructed of a sheet of tank steel. It was of welded construction seven feet by five feet and was two feet deep. It was filled to a depth of one foot with water from Tank 612. A thin layer of transformer oil (five gallons) was placed on the water to seal it and keep out oxygen. A corrugated iron shed roof was placed over the tank to keep out rain and direct rays of the sun. One 17-pound magnesium anode was placed outside the tank and a lead wire welded to the tank through a suitable shunt, and a variable resistor. The area in contact with the ground was 35 square feet.

One 17-pound magnesium anode was placed inside the tank supported one inch from bottom and three inches from one end and one side. The inside anode lead wire also was welded to the tank through a suitable shunt and a variable resistor. The area in contact with the electrolyte was 59 square feet. The anode was visible through the electrolyte and the transformer oil. Original output was 6,000 ma, cutting back to 2,500 ma after two hours. Tank to electrolyte potential varied from 1.10 volts reference to copper sulfate electrode over the anode to 0.56 volts at the farthest corner from the anode.

The chloride content of the water was 16,911 ppm. Violent gassing was observed at the anode and small gas bubbles were observed clinging to the inside of the tank shell.

On March 31, 1952, the anode output was 2,500 ma and potentials varied from 1.30 over the anode to 1.10 at the far corner. A white deposit was being formed inside the tank at all points in contact with the electrolyte. On April 7, 1952, the current was restricted to 164 ma and potentials varied from 1.02 to 0.95 volts. On May 16, 1952, the current was restricted to 60 ma and potentials varied from 0.95 to 0.92 volt.

On January 5, 1953, the anode output was 25 ma and potentials varied from 0.92 to 0.96 volt. The resistance was still 12 ohms but temperature effects reduced the output while the potential was held practically constant. A check on June 6, 1955, disclosed a 38 ma output with potentials ranging from 1.05 to 1.06 volts.

Potential measurements were made at various points inside the test tank and it was found that the potential was highest over the anode and lowest at the farthest corner. Information gained was used as a basis for restricting the anodes inside the working tanks.

The east anode inside Tank 612 was removed on January 3, 1953, and was found to weigh 3 pounds-14 ounces. Data presented in Figure 2 indicate a measured output of 666 ampere hours per pound was obtained from the east anode. It was replaced with a 17-pound anode. On February 27, 1953, the south, west and north anodes were removed and found to weigh 3 pounds-3 ounces, 4 pounds-2 ounces, 3 pounds-12 ounces, respectively. These anodes were saved for display purposes and were replaced with 17-pound anodes.

In August, 1954, the Tank 612 was again cleaned, the anodes weighed and placed back in the tank. It was concluded that four 17-pound magnesium anodes will protect the inside tank bottom and the lower portion of the shell from corrosion for three to four years. They can be inspected at any time and a technician is not required to tell when they are in need of replacing. Approximately $10.00 per year seems to be a very small annual expense for material to protect a tank whose replacement cost is about $10,000.

Acknowledgment

The author is grateful to the Tidal Pipe Line Company and Tide Water Associated Oil Company for permission to publish this paper. He thanks O. R. Tisdale, Chief Engineer, Tidal Pipe Line Company, for his assistance. It was at Mr. Tisdale's suggestion that the test tank was built and time allotted the author to make the necessary test measurements.

Publication 56-9

Cell Corrosion on Lead Cable Sheaths

Third Interim Report of Technical Unit Committee T-4B on Corrosion of Cable Sheaths by Task Group T-4B-1 on Corrosion of Lead and Other Metallic Sheaths*

Abstract

Action in a concentration cell is described briefly and shown in an accompanying diagram. A case involving attack on lead cable sheath by differential aeration cell action is described. The center portion of the cable was not attacked because it was pressed tightly against the inner surface of the tile duct. During the time the cable was in this position, water of varying amounts formed a meniscus extending from the sheath surface to the tile and reaching all the way around the dry area. Immediately outside of the area pressed against the tile, the lead had been removed by anodic action.

A case involving galvanic corrosion of a lead telephone cable sheath is discussed. It was found that the moisture seal over the lead and steel had been destroyed, exposing the metal coverings to attack by electrolytes of the soil. The effect of pH on polarity of lead and iron in a common electrolyte is shown in a diagram.

THE CORROSION HANDBOOK defines the concentration cell as "an Electrolytic cell, the emf of which is due to a difference in concentration of the electrolyte or active metal at the anode and cathode." It is usually considered that the anode and cathode are different areas of the same metal and the electrolyte an aqueous solution that can produce mobile ions.

Numerous conditions can be found which will produce differences in the concentration of an electrolyte. Some of them are:

1. Gravity (heavier concentrations of a solution will accumulate at lower levels in a container).
2. Motion of an electrolyte (portions will be kept in fresh condition and other portions will become stale).
3. Evaporation (loss of liquid, such as water, is faster at some areas than at others).

If a piece of metal is in contact with the electrolyte at its various concentrations under any of the above conditions, voltage produced at one concentration will be greater than at another concentration. The potential difference resulting will produce a current circulating between the metal and the electrolyte.

To put it another way, corrosive liquids dissolve metal as ions. The metal is said to have a solution potential with respect to the solution. That is, the magnitude of the voltage at any minute junction between the metal and liquid depends upon the concentration of the metal ions at that junction. If at another junction the concentration of metal ions is different, the voltage is a different value and the difference of the two potentials produces a current as the metal ion concentration tends to equalize. The metal area in contact with the electrolyte of low metal ion content tries to catch up with the metal ion concentration of the other area by solution of the metal. The area under attack is called the anode and the area in contact with electrolyte of excess metal ions is called the cathode. This is shown in Figure 1.

Differential Aeration Cell

There is a variation of this concept in considering differences in dissolved oxygen in a solution in contact with a metal. If there is a junction where the electrolyte has lower dissolved oxygen than at another junction, the unbalance also results in metal being taken into solution. This form of concentration cell is frequently referred to as a differential aeration cell.

Figure 2 illustrates attack on lead cable sheath by differential aeration cell action. The cable was in an underground cable duct in Galveston, Texas. The center portion of area shown was not attacked because it was pressed tightly against the inner surface of the tile duct. During the time the cable was in this position, water of varying amounts formed a meniscus extending from the sheath surface to the tile and reaching all the way around the dry area. Immediately outside of the area pressed against the tile where the water was farthest from contact with air and also

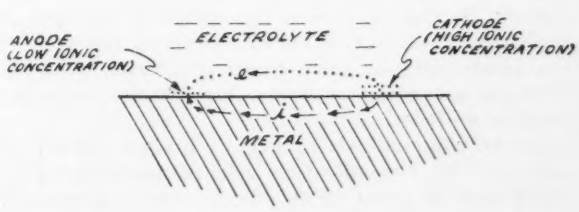

Figure 1—Diagram showing action in concentration cell.

* T. J. Maitland, American Telephone and Telegraph Co., New York, N. Y., chairman.

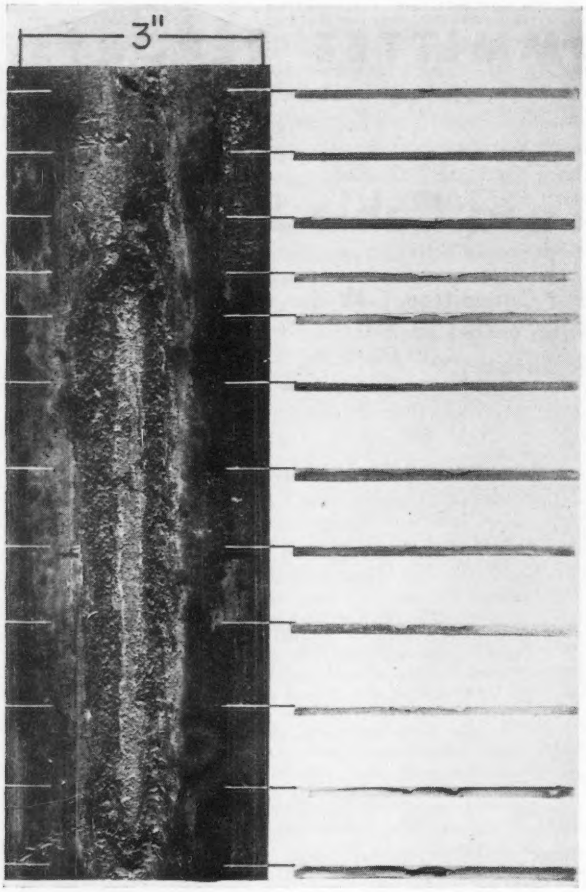

Figure 2—Lead cable sheath after attack by differential aeration cell action.

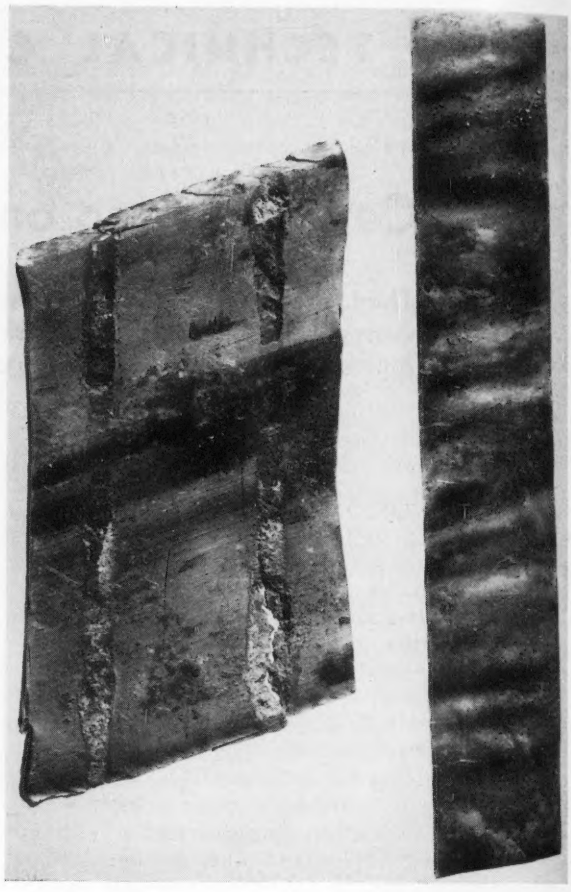

Figure 3—Specimens removed from a corroded transcontinental telephone cable.

was lowest in oxygen content, the lead has been removed by anodic action. In the differential aeration cell the lead in contact with the water closest to the air is the cathode and does not undergo attack.

The full view at the left of Figure 2 was prepared by pointing the camera directly at the specimen after it had been flattened to give uniform focusing over all of the lead surface. Then the specimen was cut and the cut edges photographed to obtain the sectional views shown at the right of Figure 2.

Concentration cells may be larger than shown by this specimen but usually they are much smaller. Sometimes they span only a tiny fraction of an inch. Their potentials usually are small but inasmuch as the current path is very short and the resistance is very small, considerable current flows and the corrosion is severe. The fastest attack, of course, will occur when the electrolyte is a good conductor of electric current. As can be seen in this example, the area of the cathode junction was several times the area of the anode junction. The metal was eaten away to form pits extending a considerable distance below the original surface.

In the communications field, a greater variety of corrosion by concentration cells is perhaps recognized than in other fields of corrosion engineering. As is exhibited by this specimen, it occurs in underground cable plant. It occurs at innumerable places where metal is in contact both with water and air. Crevice corrosion, pitting and corrosion under scale almost invariably are produced by differential aeration cells which are concentration cells.

Magnitude of Voltage

Two statements in the literature have been found that indicate the magnitude of voltage produced in differential aeration cells. One was made by Dr. R. M. Burns in the Bell System Technical Journal in 1936 and concerned differential aeration attack on lead. He reported that the largest voltage he had observed under these conditions was .1 volt. I. A. Denison reported in an article titled "Electrolytic Measurement of the Corrosiveness of Soils" in Bureau of Standards Journal of Research in 1936 (pages 363-387) that he had measured potentials as high as ½ volt when making differential aeration tests in soil samples.

An example of unusual galvanic corrosion is shown in Figure 3. The specimens pictured were removed from a corroded transcontinental telephone cable, the lead sheath having been anodic in contact with the steel tape and moist alkaline soil. The lead sheath and steel tape were part of the covering on a gopher protected cable buried in the earth near North Platte, Nebraska.

The lead sheath on this type of cable is of the same composition as that on other lead sheathed cables. It is wrapped with the steel tape along with coverings of rubber compound and fabric to prevent penetration by gophers which may infest the ground where the cable is installed.

In this instance the moisture seal over the lead and steel was destroyed, probably by gophers, exposing the metal coverings to attack by electrolytes of the soil. The pH of the electrolyte here was slightly above 10, which is much higher than is ordinarily found.

This illustrates a characteristic of lead to exhibit different polarity with respect to another metal in electrolytes of different pH. When iron and lead are in contact with an electrolyte both release molecules which produce ions in the electrolyte. The ions produced at the lead surface in acid or neutral electrolytes outnumber the ions produced at the iron surface and the lead is cathodic. On the other hand as the electrolyte becomes increasingly alkaline the decrease in the concentration of lead ions is faster than the decrease in the concentration of iron ions. At pH slightly above 10 the iron ions outnumber the lead ions and the change of polarities takes place. In electrolytes of this or greater pH, lead is anodic with respect to iron. This is illustrated in Figure 4.

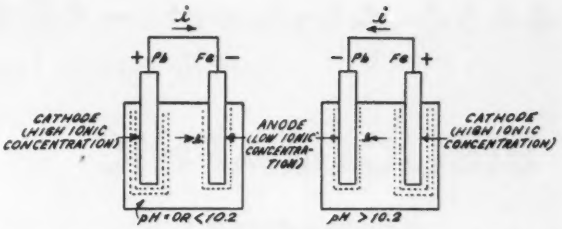

Figure 4—Diagram showing effect of pH on polarities of lead and iron in common electrolyte.

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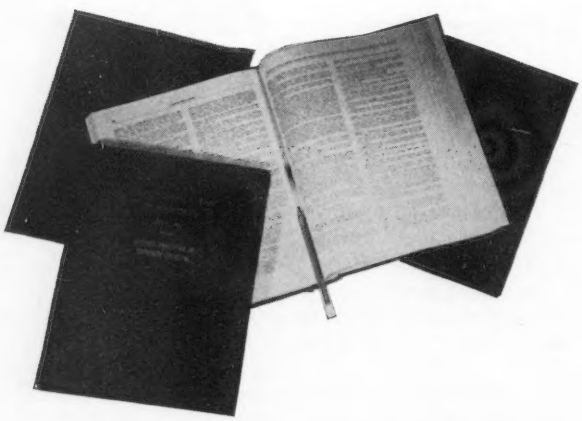

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Fouts and Erickson Will Head New T-7 Group

Stainless Steel Advocated for Power Plant Salt Water Recirculation

Type 302 stainless steel screens, link belts and rollers of revolving screens in the salt water circulating tunnels of an electric generating plant probably are more economical than either galvanized, copper or cathodically protected metals. This opinion was given during a discussion among members of Unit Committee T-4-F on Materials Selection for Corrosion Mitigation in the Utilities Industry by F. E. Kulman, Consolidated Edison Company of New York, Inc. Mr. Kulman has accepted temporary chairmanship of the committee.

Mr. Kulman said while stainless is more expensive in first cost, it probably will outperform other metals and show cost advantages over cathodically protected metals in like service.

Monel for Flooded Manholes

Further discussion in the committee meeting held during the NACE 12th Annual Conference in New York concerned tests showing Monel might be satisfactory material for sheet metal tanks for electric capacitors in submerged cable manholes. The material selected must be resistant to contaminated tidewater and to galvanic corrosion when connected to lead sheathed cable. Field tests are to be made.

Other topics discussed included variety of weather encountered in utility operation at Alaskan air bases, gas distribution problems and water system conditions, problems in the electric power industry and corrosion of electric tower footings and copper ground rods.

Task Group Reorganized

Task Group T-4F-1 on Water Meter Corrosion was reorganized and renamed T-4F-1 on Materials Selection in the Water Industry. A new task group called T-4F-2 on Materials Selection in the Electric Industry was formed. Addi-

(Continued on Page 83)

COMMITTEES INVITED TO THESE MEETINGS

Northeast Region: October 15-17, 1956, Drake Hotel, Philadelphia. October 15 reserved for technical committee meetings. To reserve meeting space notify T. J. Hull, NACE, 1061 M & M Bldg., Houston.

South Central Region: October 23-26, 1956, Gunter Hotel, San Antonio, Texas. October 23-24 reserved for technical committee meetings. To reserve meeting space notify T. J. Hull, NACE, 1061 M & M Bldg., Houston.

North Central Region: November 15-17, 1956, Detroit. To reserve meeting space notify T. J. Hull, NACE, 1061 M & M Bldg., Houston.

Corrosivity Tests Of Domestic Waters Planned by T-4E

Pipe specimens of numerous metals will be exposed for two years in numerous domestic waters in the United States by members of Unit Committee T-4E on Corrosion by Domestic Waters. Nine members of the committee are involved in the tests which will be made on pipe sections two feet in length and ranging in nominal diameter from ¾-inch to two inches. After two years of exposure specimens will be examined by T. E. Larson, Illinois Water Survey and other members.

The committee recognizes the difficulty in assessing the rates of corrosion in new pipe sections connected in systems including scaled and corroded lines. Some classification of the relative corrosiveness of the waters is hoped for, however.

During the committee's New York deliberations topics discussed included corrosion of hot water tanks, concerning which a task group is under considerations.

Liaison Functions of New Organization Described in Scope

Jack M. Fouts, New York Telephone Co., Buffalo, N. Y., and C. A. Erickson, Jr., The Peoples Natural Gas Co., Pittsburgh, Pa., have been appointed chairman and vice chairman respectively of Technical Group T-7 tentatively referred to as a "corrosion coordinating committee." The com-

Fouts

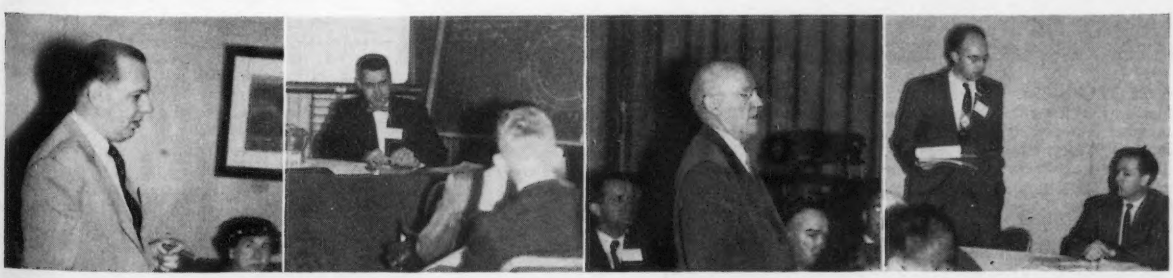
Erickson

mittee's objective is to provide coordination among the so-called electrolysis or corrosion coordinating committees organized among operators of underground metallic plant."

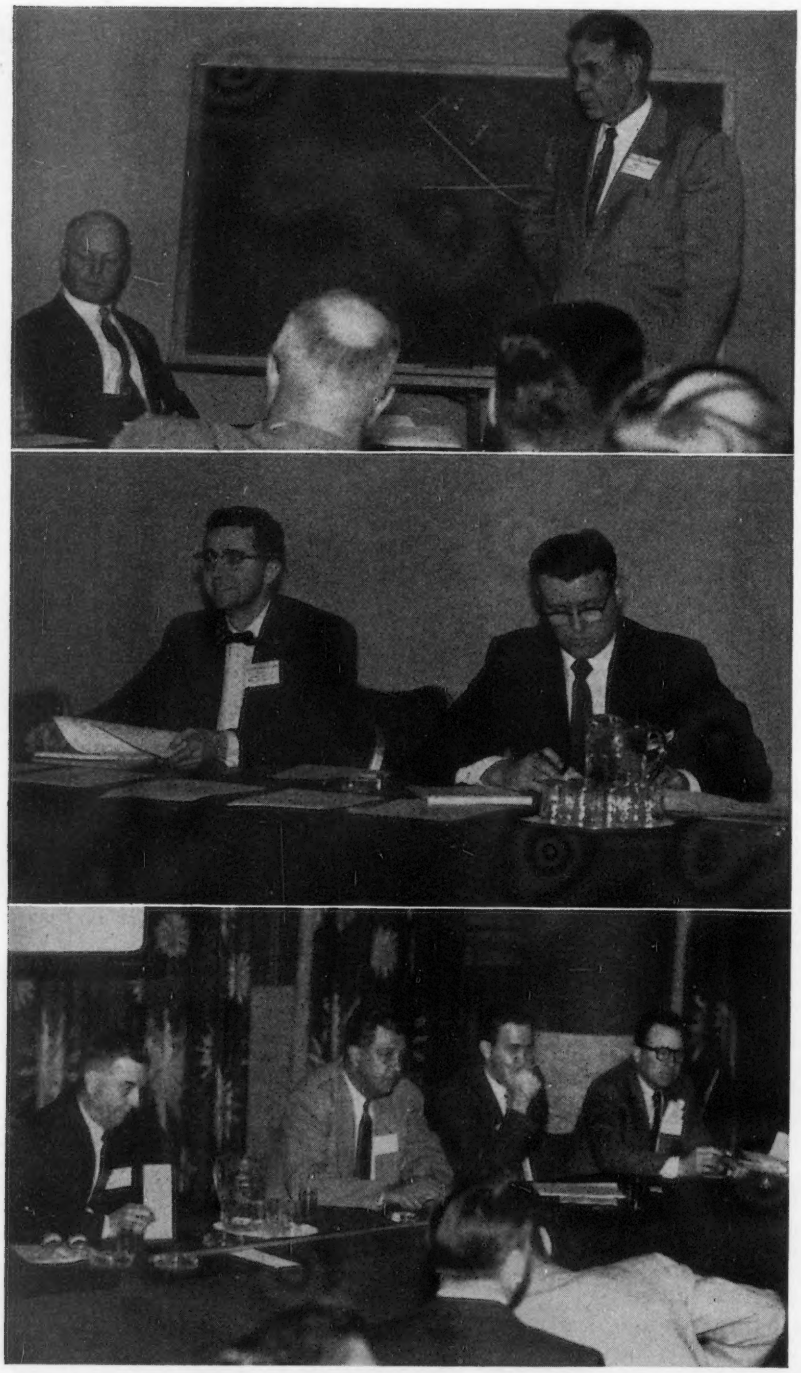
Scope of the committee has been approved as follows:

This committee is interested in promoting cooperation and providing a medium for the exchange of information between the various groups known as Electrolysis or Corrosion Coordinating Committees on the North American continent. The scope of this committee is limited to liaison functions and providing a medium for the exchange of information between Coordinating Committees. It will not engage in technical study projects as such, but may participate cooperatively with established technical units in the study of technical matters pertinent to coordination problems. It is the function

(Continued on Page 82)



TECHNICAL COMMITTEE ACTIVITIES at New York included (left to right) A. A. Brouwer, Dow Chemical Co., Midland, Mich., who discusses formation of task group to study cathodic protection in the process industries at the T-3G meeting; F. J. Radd, Continental Oil Co., Ponca City, Okla. presides at a meeting of T-1F; V. B. Pike, Bell Telephone Laboratories, Murray Hill, N. J. discusses corrosion of cable sheaths at a T-4B task group meeting; P. E. Reynolds, Pacific Gas & Electric Co., San Francisco, standing and R. J. Schmidt, California Research Corp., San Francisco, sitting, respectively vice-chairman and chairman of Unit Committee T-2H are seen at this committee's meeting.



MORE TECHNICAL COMMITTEE ACTIVITIES at New York. Top, standing, J. A. Holloway, Houston Pipe Line Co., Houston, new chairman of T-2A on Galvanic Anodes discusses pipe line corrosion problems at a pipe line group discussion; middle, left, A. H. Roebuck, Continental Oil Co., Ponca City, Okla. and right, D. A. Vaughan, Battelle Memorial Institute, Columbus, Ohio, respectively chairman and vice-chairman of T-3B are shown presiding at the committee's session; bottom, left to right, O. C. Roddey, Olin Gas Transmission Corp., Monroe, La.; A. L. Stegner, Tennessee Gas Transmission Co., Houston; T. J. Hull, NACE, Houston and Pat H. Miller, Texas Eastern Transmission Corp., Shreveport, La. are seen at the organization meeting of a gas pipe line corrosion committee.

More than 3000 entries are included in the 10-Year Index to Corrosion's Technical Section.

Copies of Corrosion's 10-Year Index can be ordered now.

Five regional NACE meetings will be held during the fall of 1956.

Topical Indices to the material published in the Technical Section of Corrosion are published annually in the December issue.

Fouts and Erickson–

(Continued from Page 81)

of this committee to collect and compile information concerning the by-laws or operating rules of the various existing Coordinating Committees and make this information available to other committee groups interested in forming Coordinating Committees in areas where none exist. It is also the function of this Committee to collect and compile information concerning notification procedures, location of metallic underground plant, corrosion protection systems operated on the underground plant and personnel responsible for corrosion work on underground structures in each locality. All of the information compiled by this Committee will be made available for exchange within the various units as may be required to assist the members in maintaining cooperation and coordination between the Committees in the various localities. The Committee will study the information obtained and make recommendations for simplication and uniformity in coordinating procedures when deemed advisable by the members. As a long range project it is the objective of this committee to condense and consolidate pertinent information into a directory or handbook that will require a minimum of effort to keep up to date. The scope of all unit committees under this group shall be identical with the Group Committee scope with the functions of each unit committee confined to its own Region.

Organization of T-7 will be as follows: 1. Unit committees will be organized with geographical limits coincident with those of NACE regions. These units will consist of a chairman and vice-chairman and chairmen of cooperating local electrolysis committees which will be called task groups. 2. Chairmen of cooperating electrolysis committees will be invited to cooperate with the unit committee and to become chairmen of the task groups.

All Work at Local Level

The organization will not interfere with the autonomy of existing electrolysis or corrosion committees or with the autonomous operation of any task group organized later at the local level. Task groups will be asked to supply reports on their activities to their respective unit committees and encouraged to supply information useful to other local groups.

Essentially, the purpose of T-7 will be to provide a means of communication among local area task groups. A long term aim will be to standardize by-laws of task groups. Existing electrolysis or corrosion committees are invited to become members of the organization. Additional information can be obtained from Mr. Fouts, New York Telephone Co., 63 East Delavan Ave., Buffalo 8, N. Y.

Mr. Fouts will name temporary chairmen of the six unit committees for organizational purposes. An election of officers will be held in each unit after organization.

Mr. Fouts, who has been a member of NACE since 1952, has been engaged in corrosion work with the New York Telephone Company for six years. He currently is chairman of the Niagara Frontier Section of NACE and was chairman of the 1955 North East Region meeting on underground corrosion.

Report on Coatings to Protect Steel Exposed to Atmosphere Is Completed

A report on coatings systems suitable for protecting steel structures exposed to normal rural, industrial and marine atmospheres has been completed by Unit Committee T-6B on Protective Coatings for Resistance to Atmospheric Corrosion. It is now being voted on by committee members and if approved is scheduled for publication in an early issue of CORROSION.

It is concerned primarily with protection of structures such as bridges, tanks, towers, fences and railroad cars exposed to rural, industrial and marine atmospheres, excluding the strongly corrosive chemical or marine atmospheres.

Coatings materials covered have wide variations in resistance to water, oxygen, sunlight and chemicals and vary in physical characteristics and application requirements. The report includes a chart listing 22 types of coating, recommended surface preparation, number of coats, approximate dried film thickness, approximate air drying time, usual methods of application, application surface temperature, thinners, solvents, general flammability classification, compatibility with other types of coatings, abrasion resistance, gloss retention, resistance to petroleum oil and grease, maximum temperature limitations, approximate storage life and health safety precautions.

Howard C. Dick, Products Research Service, New Orleans has been elected to succeed L. L. Sline, Sline Industrial Painters, Houston as chairman of Unit Committee T-6B. Mr. Dick has been vice-chairman for two years. A new vice-chairman will be elected.

During the committee's session in New York during the NACE 12th Annual Conference it was agreed work will be done now on new coating materials and improved versions of earlier materials covered in the committee's report. A task group will be named to study new work for the committee.

Stainless Steel—

(Continued from Page 81)

tional task groups will be organized as needed to cover such utilities as steam and gas.

Daniel Cushing, Consulting Metallurgist, 148 State St., Boston is temporary chairman of Task Group T-4F-1 on Materials Selection in the Water Industry. He is making plans for activities of his group and welcomes inquiries concerning membership.

L. P. Shaefer, The Hinchman Corp., Francis Palms Bldg., Detroit, is temporary chairman of Task Group T-4F-2 on Materials Selection in the Electric Industry. He invited all NACE members interested in this committee to write him.

F. E. Kulman, Consolidated Edison Co., New York, Inc., 4 Irving Place, New York, N. Y. invites membership in T-4F or submission of materials selection problems.

•

Technical articles published in Corrosion come from many foreign countries including Egypt, Germany, Australia, New Zealand, Israel, France, Belgium and Japan.

Coating Conductance Revision Is Finished

First revision of the report "Proposed Standard Method for Measuring Electrical Conductance of Coating on Buried Pipe Lines" has been completed by Unit Committee T-2D on Standardization of Procedures for Measuring Pipe Coating Leakage Conductance. The report is in process of approval prior to publication. T-2D has asked that the NACE board of directors approve the report before it is published.

Marshall E. Parker, Houston reported at New York on the progress made by Task Group T-2D-1, presenting the group's report on short insulated pipe sections of low conductance. The group plans to extend its present study and prepare the report for publication.

Asphalt Type Pipe Coatings Ballot Scheduled Soon

Balloting on acceptance of the report of Technical Unit Committee T-2H on Asphalt Type Pipe Coatings is scheduled soon. The committee completed its work on the report during the March NACE conference in New York.

R. J. Schmidt, California Research Corp., Richmond, has resigned as chairman, so a new chairman will be elected. P. E. Reynolds, Pacific Gas & Electric Co., San Francisco, Calif., will remain vice-chairman.

WHEN IT COMES TO SERVICE

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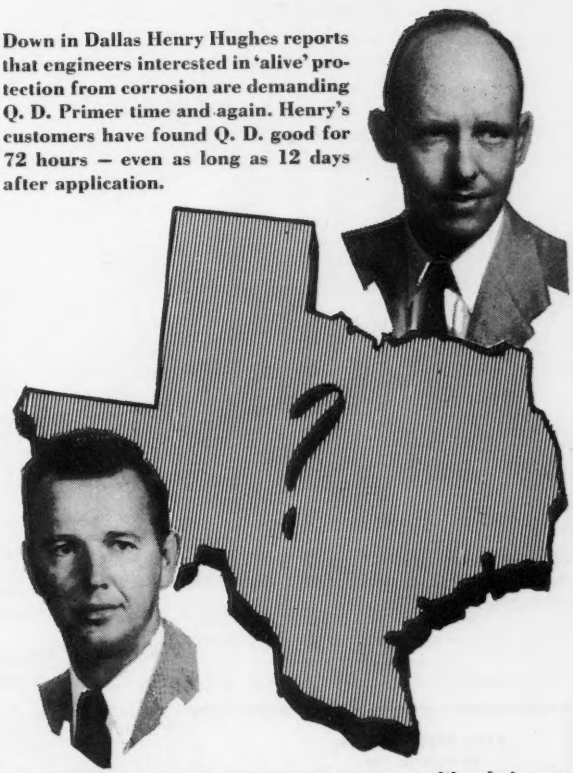
• Down in Dallas Henry Hughes reports that engineers interested in 'alive' protection from corrosion are demanding Q. D. Primer time and again. Henry's customers have found Q. D. good for 72 hours — even as long as 12 days after application.



• Pipeline men in the Houston area are like their contemporaries in other localities — they want good protective coatings and practical suggestions from the manufacturer concerning application procedures. Bill Sandland is ready to supply help at all times.

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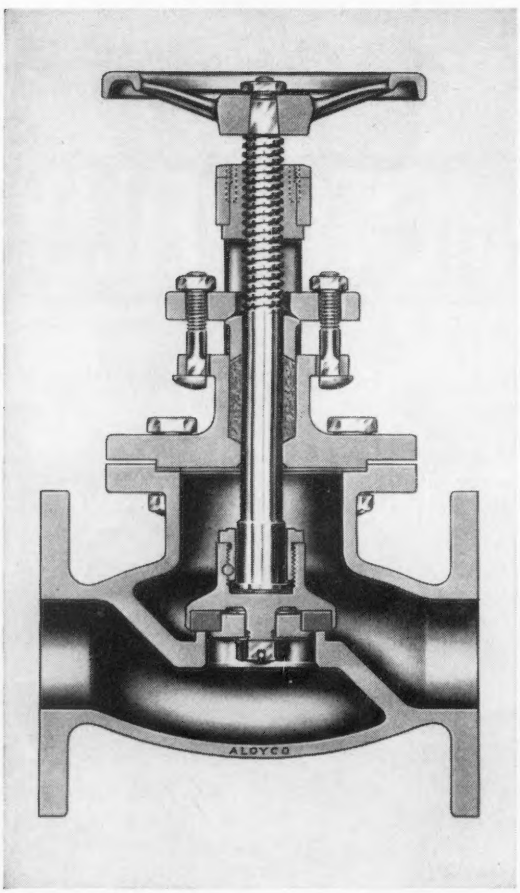

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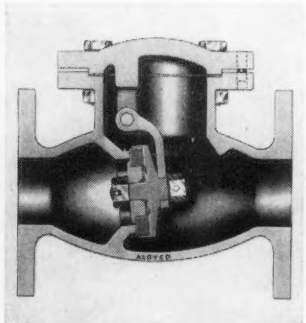

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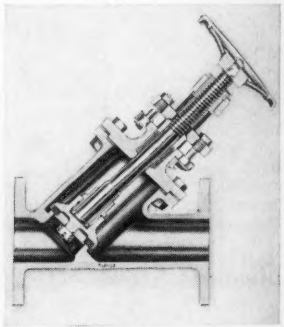

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Larrabee Cites Growth of Technical Committees

More Reports and Increased Activity Noted by Chairman

By C. P. Larrabee, Chairman
Technical Practices Committee

(Summary of Report of the Technical Practices Committee to the President of NACE, March 13, 1956)

The activities of the technical committees of the association have been gathering momentum since their reorganization in March 1954. This activity has been shown especially in the number of technical committee reports that have been published in CORROSION. During the year March 1955 through March 1956, sixteen technical committee reports have been published. These reports varied from simple statements of the progress made by a committee to a report on the results of a four-year committee testing program. Almost 4000 reprints of these reports were given to Corporate Members of the Association. More than 1000 reprints of reports were sold by Central Office. An additional 1000 were given to committee members.

In addition to the sixteen reports published, four more have been completed and approved for publication. At least six more reports are complete but have not yet been approved for publication.

Only one new unit committee was formed during 1955-1956. This is Unit Committee T-5E on Stress Corrosion Cracking of Austenitic Stainless Steels. This does not, however, indicate that only one new activity was initiated. Thirty-five new task groups were formed, each with a specific assignment to study. In addition, seven project committees (sub-groups of task groups) were formed.

Twenty-seven committees held meetings at regional meetings this year. The technical committees are being encouraged to take advantage of facilities offered by regions to hold meetings between National Conferences. It is hoped that in the future all committees will have at least two meetings each year.

The technical committees are cooperating with other organizations on nine different projects. The degree of cooperation varies from financial participation and representation on a joint committee to simple liaison which consists of an exchange of information. Cooperation on four additional projects is now being considered.

The number of individual members on technical committees has grown by almost 20 percent since March of 1955. This indicates a growing awareness by NACE members of the value of participation in technical committee activities. To get the most out of a membership in the association, one should be active on at least one technical committee. Some NACE members participate in the activities of as many as ten committees.

The technical committee reorganization and Technical Committee Operation Manual has been in effect for two years. The increase in activity is evidence that the move was a good one. There have been some changes made in the manual and there is every probability more changes will be made. In general, the technical committees are satisfied with the manual and very little objection has been expressed.

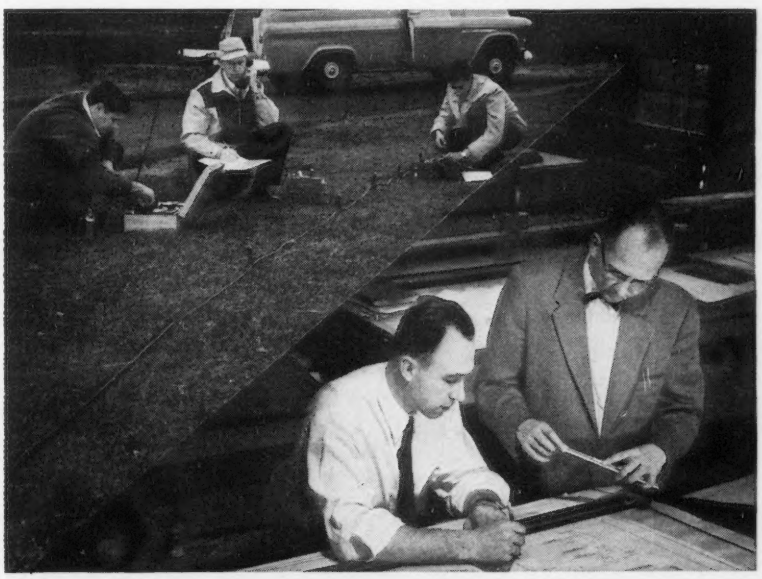
The Technical Practices Committee continues to act as a policy making group and has had relatively little to do during the past year. The Managing Committee, composed of the chairman and vice-chairman of the Technical Practices Committee and the vice-president of the association, has served as the executive group for the Technical Practices Committee between meetings of the latter.

We do not think the technical committees have reached the peak of their activities. The scope of study will continue to grow as the association grows. Conversely, the association will grow as the technical committee work expands and achieves recognition by industry.

Chlorine Data Sought

A questionnaire on corrosion by chlorine will be circulated soon by Task Group T-5A-5 on Chlorine. A bibliography prepared by this committee was published in CORROSION's March issue. Reprint copies are available at $1.50 a copy.

At the group's New York meeting in March an eventual project of the committee was suggested to be determination of types of equipment most suitable for service in handling chlorine.



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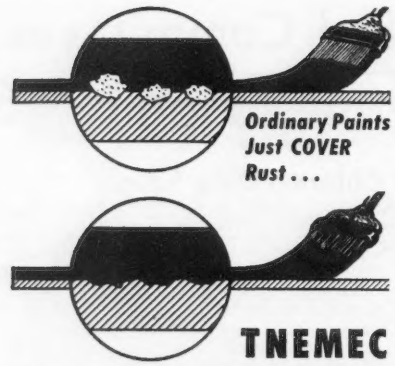

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Five Task Groups Named By Petroleum Production Protective Coatings Unit

Five task groups have been proposed to carry on the work of Unit Committee T-6E on Protective Coatings in Petroleum Production. The subjects they will study are: 1—Tanks (stock and storage). 2—Pipe. 3—Heaters (treaters and evaporators). 4—Miscellaneous Oilfield Equipment (christmas trees, structural steel, pumps, motors, etc.). 5—LPG Plants (including coolers, hot stacks, etc.).

Work of the groups will include, where appropriate, recommendations on: exposure, external and internal; surface preparation, materials selection, inspection procedure and experience.

F. T. Rice, The Pure Oil Co., Chicago is chairman of T-6E. An election of a vice-chairman is underway.

Temporary Chairmen Are Named for T-5B Groups

Temporary chairmen have been obtained for two task groups of T-5B proposed in March, 1955. J. J. Halbig, Armco Steel Corp., Middletown, Ohio, chairman of T-5B reported also that Task Group T-5B-4 on High Temperature Halogenation has been terminated because of insufficient interest in the subject.

R. T. Foley, General Electric Co., Schenectady, N. Y. is temporary chairman to organize Task Group T-5B-3 on Oil Ash Corrosion and W. D. Manly, Oak Ridge National Laboratory, Oak Ridge, is temporary chairman of T-5B-5 on Corrosion by Molten Salts.

Unit Committee T-5B is in process of voting on new officers by letter ballot, whose names probably will be announced in an early issue of CORROSION.

Summary of Vinylidene Chloride Copolymer Report Presented at New York

A summary of the Task Group T-6A-3 report on vinylidene chloride copolymers was presented at the New York meeting of Unit Committee T-6A. Following the scheme used by T-6A in previous reports it covers definition of the resins, description of resistance properties, properties of applied coatings and linings, such as temperature limitations; weatherability, abrasion resistance and application. Overall chemical resistance of the material was said to be outstanding in comparison with some other organic solution resins.

The report will be reviewed by T-6A and ultimately voted on for publication.

Air Pollution Bibliography

Library of Congress will prepare a continuing, annotated bibliography on air pollution for the Public Health Service, including references to physical, biological, engineering, legal-administrative and economic aspects of atmospheric pollution.

One-Third of Water Treating Chemicals Said to Be Wasted

As much as one-third of the expenditures of 16 Gulf Coast refinery and chemical plants for treatment of cooling water is unnecessary. This conclusion is reached in a report by NACE Task Group T-5C-1 on Cooling Water Corrosion in the South Central Region. These plants spend $407,000 annually for water treating chemicals, so the wasted money amounts to $134,000 a year.

The report highlights also the fact plants in the group surveyed are remarkably conservative in use of water. Only 5.5 percent of the total used is wasted; of 15,300 gallons per minute used for makeup, only 850 gpm are dissipated.

These facts are discussed in and supported by data in the report. Potential savings and reasons for excessive use of treating chemicals are covered also. The report is scheduled for publication in the near future.

T-5C-1 has decided to reactivate its committee on once-through cooling water to seek data to be added to what is known already for compilation in a report.

The non-ferrous alloys and stainless steels project committees of T-5C-1 report that materials for stress corrosion testing are being received and that exposure will begin soon.

Cathodic Protection Studies

Unit Committee T-3G on Cathodic Protection has formed three task groups. They are:

To study cathodic protection of ship hulls, L. P. Sudrabin, Electro Rust-Proofing Corp., Newark, chairman.

On application of cathodic protection to heat exchangers, R. B. Teel, The International Nickel Co., Inc., Wrightsville Beach, N. C., chairman.

On application of cathodic protection to process equipment, A. A. Brouwer, The Dow Chemical Company, Midland, Mich., chairman.

Sweet Oil Well Inquiry

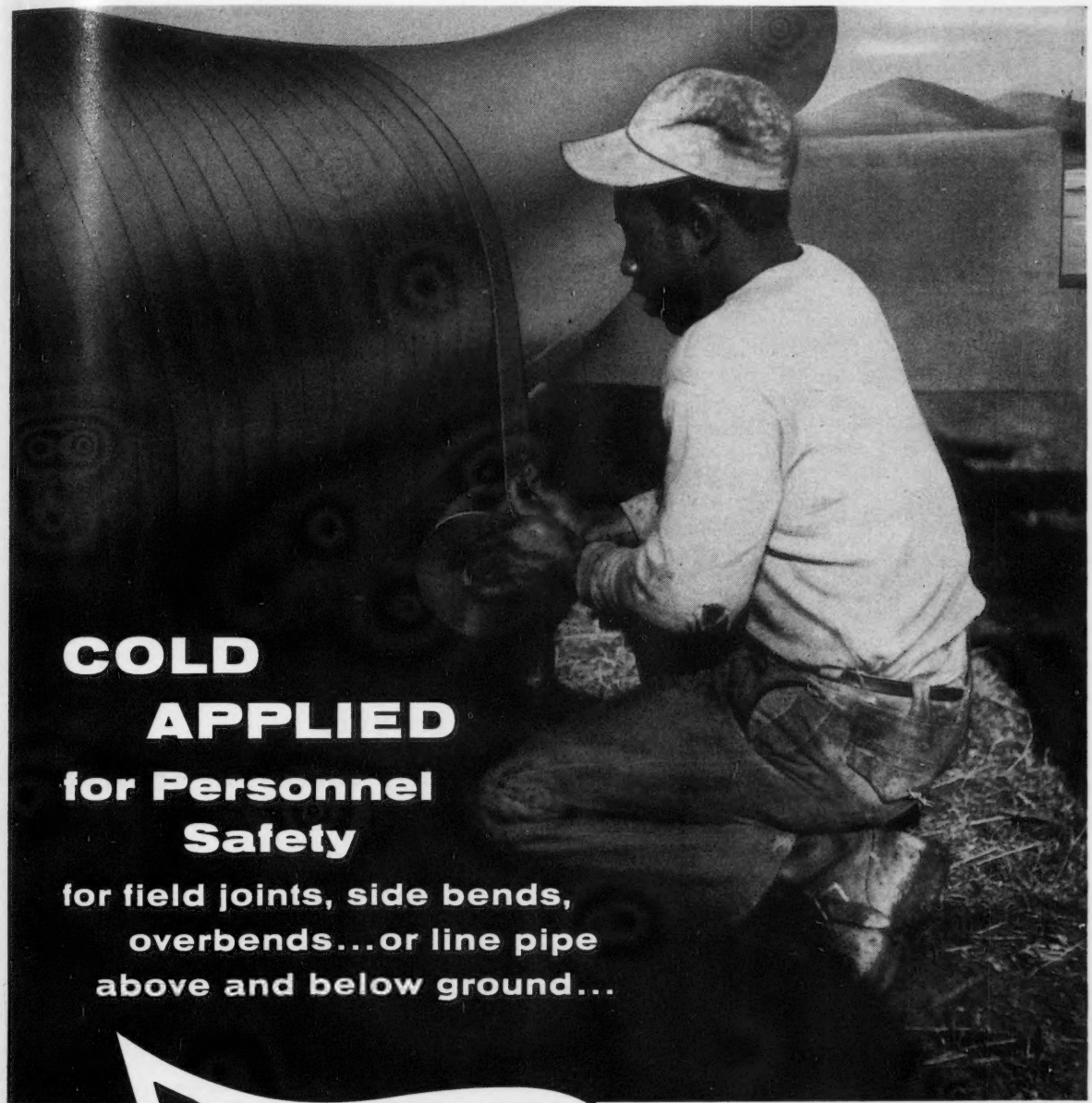
Inquiries into specific aspects of corrosion associated with the operations of sweet oil wells is projected by Unit Committee T-1C on Sweet Oil Well Corrosion. Subjects suggested for study include coated tubing, treating methods and types of well completion.

J. T. Clayton, The Texas Company, Houston and Rado Loncaric, Atlantic Refining Co., Dallas have been elected chairman and vice-chairman respectively of the committe.

Joint Distribution Set

Joint distribution by ASTM Committee A-10 on Iron-Chromium, Iron-Chromium-Nickel and Related Alloys and NACE T-5E on Stress Corrosion Cracking of Austenitic Stainless Steels of a questionnaire on stress corrosion cracking of stainless steels is contemplated. Each committee will compile and exchange data.

T-5E has asked that M. E. Holmberg, Houston be appointed liaison member of the ASTM committee.



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NACE NEWS

BALTIMORE SECTION'S new officers and some guests are seen in this picture taken at the February 16 meeting at the Park Plaza Hotel. Left to right, J. H. Parran, Weather-Mastic, Inc., vice-chairman; Mars G. Fontana, Ohio State University, guest speaker; B. J. Philibert, Olin Mathieson Chemical Corp., chairman; C. H. Elliott, Jr., Davison Chemical Corp., secretary-treasurer; K. M. Huston, Armco Steel Corp. and George E. Best, Mutual Chemical Division, Allied Chemical & Dye Corp., regional director.

West Kansas Section Is Organized April 17

South Central Region gained one section to bring its total to 13 while North Central lost the Casper, Wyoming section, organization of which was abandoned. The new section is the West Kansas Section which held its organization meeting April 17 at Great Bend, Kans. Total number of sections in NACE remains 51.

Officers of the section are Thomas A. Allen, Cooperative Refinery Assoc., Great Bend, chairman; D. L. Peterson, Cities Service Oil Co., Great Bend, vice-chairman; J. P. Berry, National Aluminate Corp., Hutchinson, secretary-treasurer and W. C. Koger, Cities Service Oil Co., Bartlesville, Okla., trustee.

Engineer Week Boosted By San Diego Section

F. O. Waters, San Diego City Water Department, Dallas G. Raasch, La Mesa, Orange Grove, Spring Valley Irrigation District, La Mesa and Harry J. Keeling, of San Diego Section NACE cooperated in the celebration of Engineers' Week at San Diego by providing and arranging an extensive exhibit of equipment at the new engineering building of San Diego State College. Mr. Keeling, consulting engineer, Los Angeles spent three days arranging the display pertaining to corrosion.

The San Diego State College building was dedicated at 2 pm February 22.

In connection with the celebration of Engineers' Week, The San Diego Union newspaper published a section on the engineering organizations in the San Diego area, including data about NACE.

Hoxeng Joins Committee

R. B. Hoxeng, U. S. Steel Research Laboratories, Monroeville, Pa. has accepted appointment to the NACE Education Committee.

A. D. Simpson Is Elected To Post on NACE Board

A. D. Simpson, Jr., United Gas Corp., Houston has been elected to fill the unexpired term of W. H. Stewart as NACE director representing active membership. Mr. Stewart took office as association vice-president in March. The election was by ballot among members of the NACE board of directors.

SIMPSON

Mr. Simpson, a native Texan, an alumnus of Rice Institute, Houston, has been employed in various capacities by United Gas Corporation since 1931. Starting work as a rodman on a field survey party he successively became party chief on surveys, distribution district engineer for the Southwest Louisiana Territory, assistant chief engineer and division superintendent for the company's East Texas Division. In January, 1946 he was named chief engineer of the Operating Division, with headquarters in Houston with supervision over construction, maintenance and operations of physical properties, including valuation and standardization work, cathodic protection and radio communication.

Among other organizations he is a member of the Houston Engineer's Club, Texas Society of Professional Engineers, AGA Management and Corrosion Committees, Southern Gas Association.

North Central Region

The first annual meeting of North Central Region NACE will be held November 15-16 at Hotel Statler, Detroit.

Binger Speaks at Session Of Kanawha Section

Thirty-four members and guests attended the January 19 meeting of the Kanawha Valley Section to hear Mr. Binger, Aluminum Company of America speak on Corrosion Behavior of Aluminum in Different Chemical Environments.

Results of the recent section election are as follows: Jack Bates, Carbide and Carbons Chemicals Co., chairman; George Klohr, E. I. du Pont de Nemours Co. Inc., vice-chairman; Fred Lloyd, United Fuel Gas Co., treasurer; and George Walther, Food Machinery and Chemical Corp., secretary.

The next section meeting is scheduled March 29 at the Kanawha Airport where Dr. H. C. Gatos was programmed to present a paper on Corrosion Inhibitors, Theory and Practices.

Southwestern Ohio's New Officers Are Named

At the Southwestern Ohio Section meeting February 28 it was announced the following become officers at the close of the April 24 meeting: Cliff Jones, Cincinnati Gas & Electric Co., chairman; Sol Gleser, A. M. Kinney, Inc., vice-chairman; R. Leonard Wood, Cincinnati Gas & Electric Co., treasurer; William Hare, Hare Equipment, secretary. R. F. Andre, Rex Stephenson, Josephine Williams, David Jones, William Spurgeon and Lewis M. Lederer are section directors.

Approximately 25 members and guests attended.

Painting Problems Covered At Sabine-Neches Meeting

Approximately 50 members and guests attended the March 29 meeting of the Sabine-Neches Section. Vernon M. Brown of Columbia Southern Chemical Corporation was moderator for the round table discussion which covered painting problems such as plant paint test programs, inspection methods, new coating developments, designs for better painting, weather protection of steel pipe and masonry sealing paints.

Joseph Waterfield, of United Gas Corporation was scheduled to discuss Corrosion Problems in the Gas Industry, at the April 26 meeting of the section.

Carpenter Talks on Amines

Approximately 20 members and guests attending the March 27 meeting of Central Oklahoma Section heard Dan H. Carpenter of the Aquaness Department of the Atlas Powder Company speak on Internal Corrosion in Gasoline Plants and Refineries and discuss the use of filming amines in controlling corrosion. The next meeting of the section will be on May 24.

ISCC Chairman Succumbs To Injuries From Fall

Richard Marks Wick, metallurgist for Bethlehem Steel Co., Allentown, Pa. for two years president of the NACE Inter Society Corrosion Committee died February 18 at Baltimore as the result of injuries suffered in a fall. Dr. Wick, 52, was connected with Bethlehem Steel for 20 years, conducting tests and developing processes for coating steel with tin, copper and nickel. He had done similar work for the Navy at Philadelphia and for the National Bureau of Standards.

Wick

He held a bachelor's degree from Massachusetts Institute of Technology and a doctorate from Johns Hopkins University, Baltimore.

He was a registered professional engineer and a member of the Pennsylvania Society of Professional Engineers, the American Chemical Society, Lehigh Valley Engineer's Club, American Electroplaters Society and NACE, among others.

He is survived by his widow, two sons and his mother.

Fleming Gets Certificate

Paul Fleming was awarded a past chairman's certificate by North Texas Section during its April 2 meeting held at the Torch Restaurant, Dallas. Following the presentation approximately 25 members and guests heard S. J. Bellassai of Transcontinental Pipe Line Company speak on Induced Alternating Current Used for Cathodic Protection of a coated Pipe Line.

Following Mr. Bellassai's talk final arrangements for the section's annual picnic to be held in May were announced.

Robinson Is Elected New Orleans-Baton Rouge Section Chairman

The following officers were elected by the New Orleans Baton Rouge Section at its March 29 meeting; R. M. Robinson, Continental Oil Co., chairman; O. L. Grosz, The California Co., vice-chairman; W. J. Eads, Products Research Service, Inc., secretary-treasurer; and L. N. Spinks, Cathodic Protection Service, trustee. Following the election the 24 members and guests present heard Paul E. Weaver of the Allied Chemical and Dye Corp. speak on Maintenance Painting.

Mr. Weaver discussed the total annual cost of corrosion and explained numerous methods are being used to decrease these costs. As these methods are too varied to cover in a single meeting Mr. Weaver chose to discuss Sandblasting Cleaning For Painting and to explain misunderstanding of such cleaning methods and the importance of choosing the proper materials and equipment for this work.

Mr. Weaver pointed out common river sand contains a too-high dust-to-sand grain ratio to be effective as blasting material. He advocated the use of hard, irregular, and angular sand grains. In his discussion of equipment Mr. Weaver stressed the need for properly designed and sized compressors, hoses, nozzles and discussed the efficiency losses due to use of improperly designed equipment. He also indicated the economic desirability of proper training of personnel for maintenance painting work.

F. J. Radd, Senior Research Metallurgist, Development and Research Department of the Production Research Division, Continental Oil Company, Ponca City, Oklahoma, lectured February 27 on Corrosion Metallurgy of High Strength Tubing and Casing. Dr. Radd discussed the effect methods of steel preparation and heat treatment, microstructure, alloying materials and impurities have upon the corrosion resistance or tendency of high strength steels at a meeting of the New Orleans-Baton Rouge Section attended by approximately 25 members and guests. He indicated steel would not suffer serious corrosion if impurities could be eliminated.

A. M. Robinson, secretary-treasurer, reported that Paul Weaver, Allied Chemical and Dye Corp., Baton Rouge, would discuss Maintenance Painting at the March meeting.

Chairmen Are Named For Niagara Section's Program on May 9-10

Chairmen of three sessions to be held during the May 9-10 symposium on Control of Corrosion in the Chemical Industry by Niagara Frontier Section have been named. A talk on the St. Lawrence seaway will be given at a dinner beginning at 7 pm May 9 in the New York Room of Hotel Statler, Buffalo. Col. Loren W. Olmstead, Buffalo District engineer, Corps of Engineers, U. S. Army, will be the speaker.

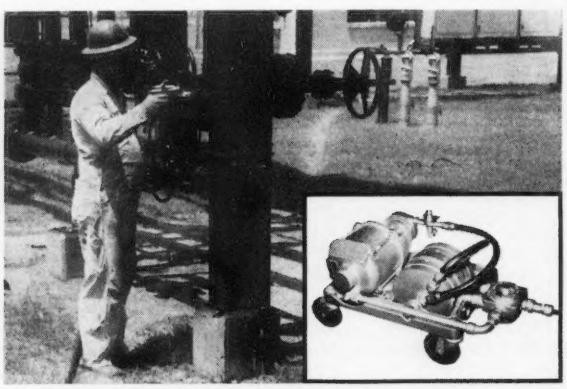
LaQUE

LUCE

William O. Binder, assistant to the manager, Product Development Laboratory, Electro Metallurgical Co., will be chairman of the May 9 afternoon session. Walter A. Luce, The Duriron Company, will be chairman of the May 10 morning session and F. L. LaQue, The International Nickel Co., Inc. will be chairman of the May 10 afternoon session.

M. C. Miller Is Speaker

M. C. Miller, instrument designer and manufacturer was the scheduled speaker at a May 11 dinner meeting of Philadelphia Section. The meeting was held at the Poor Richard Club. Mr. Miller's presentation included a soil box demonstration of corrosion and cathodic protection.



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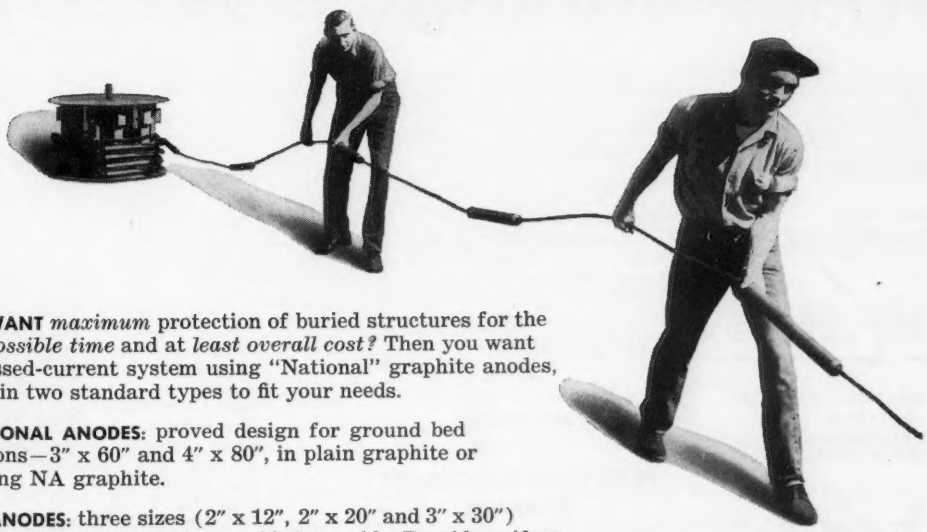

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Numerous Navy Experiments With Cathodic Protection of Ships Discussed at Houston

Results of numerous long and short term experiments with cathodic protection of active and inactive ships were related by H. S. Preiser, Bureau of Ships, U. S. Navy, Washington at a meeting of Houston Section April 10. Mr. Preiser's remarks were heard by about 75 members and guests at a dinner meeting.

Numerous interesting discoveries related by Mr. Preiser included:

1. It apparently is possible to polarize a static ship by means of a single platinum clad anode suspended in sea water at depths of 150 to 200 feet below the hull. A test is to be made soon with a platinum anode trailing 200 feet from a ship on a trans-Atlantic trip to see what effect an impressed current has on the polarity of the moving hull. No gas blocking of the platinum anodes used in Navy experiments has occurred at currents used to date.

2. Much cathodic protection is wasted on bare steel close to anodes on ship hulls. It is postulated that this accounts for poor distribution of current over hull.

3. The difference in current needed to polarize a moving versus a static ship in sea water is about two times for the moving ship. Furthermore current demand to maintain polarization is less on a moving ship that has been polarized while static.

Effects of Hydrogen

Several effects from the generation of hydrogen at anodes were related. One experiment involving magnesium anodes in sea water in a closed vessel showed that in 75 hours pressure in the closed vessel reached 135 psi and probably would have gone higher had not the experiment ended. This underlines the need, Mr. Preiser pointed out, to be sure that all tanks are properly vented when they include active cathodic protection systems. Zinc anodes created pressures near 50 psi before leveling at 200 hours.

Navy tests have not shown that medium or high strength steels are likely to suffer from hydrogen embrittlement when subjected to cathodic protection currents. Experiments were conducted at 10 to 20 ma per square foot. The experiments are continuing.

DRAWINGS of one of the cathodic protection devices developed by the Navy are explained by H. S. Preiser.

Extent of Application Given

While there are about 30 installed cathodic protection systems on active Navy ships, performance is erratic with both galvanic and inert anodes. Additional work is necessary before specifications and procedures can be drawn.

Experience has shown also, Mr. Preiser pointed out, that while criteria can be determined with some certainty for inactive ships in salt water, it is more difficult to establish minimum current demands in fresh and brackish water. Difficulties are being experienced in obtaining proper distribution of current on ship hulls in fresh water. There is some evidence also that stray currents are damaging hulls in fresh water.

Tests on Coated Panels

Tests of the effect of cathodic protection currents on panels coated with thick layers of materials were conducted at the Harbor Island test station. In these tests numerous coating systems in thicknesses from 20 to 100 mils were applied on steel and impressed currents applied in increments of 1.5 volts to a maximum of 6 volts.

The experiments were designed to determine which coating systems were best suited for dielectric shields in the vicinity of anodes. After 15 months, two systems appeared to be relatively unaffected by the electroendosmosis effects and the alkali attack, ⅛-inch Neoprene sheet and epoxy glass reinforced resin cold applied.

Coatings which exhibited best resistance to oxychloride attack, such as would be experienced in the immediate vicinity of an impressed current anode, were least useful as dielectric coatings and vice-versa, the experiment showed. The Navy has used these data to design anodes which include polyesters near the anode and other materials further away from it.

Cavitation Damage Tests

Numerous tests are underway to determine what effect cathodic protection will have on cavitation damage to hulls in the vicinity of bronze propellers. A test is underway by which it is hoped to separate the effects of cavitation and galvanic corrosion.

Other experiments include the application of cathodic protection to the stern areas of ships only, efforts to insulate new aluminum bronze propellers from steel shafts, grounding devices to complete the circuit between bronze propellers and hulls and reduce stray currents to the exterior hull surfaces.

New Platinum Anodes Developed

New kinds of platinum-clad anodes are being developed. Mr. Preiser explained and illustrated the several kinds of platinum clad anodes in use and gave details on the mountings to ship hulls. The most recent development is a circular platinum anode imbedded in a polyester and mounted on a large dielectric shield. Good results are being obtained.

Platinum clad anodes, while high in first cost, have relatively good economics compared to other types of inert anodes when considered over long periods of use. One design of graphite anode is being evaluated on units of the reserve fleet. A 12-inch in diameter high silicon anode is being tested. This anode

(Continued on Page 94)

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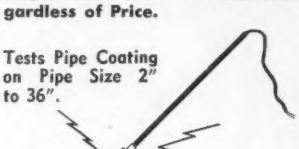

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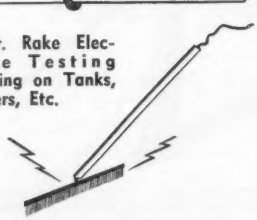

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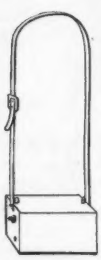

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Numerous Navy—

(Continued from Page 92)

has a central mounting stud through which the electrical connections pass into the ship.

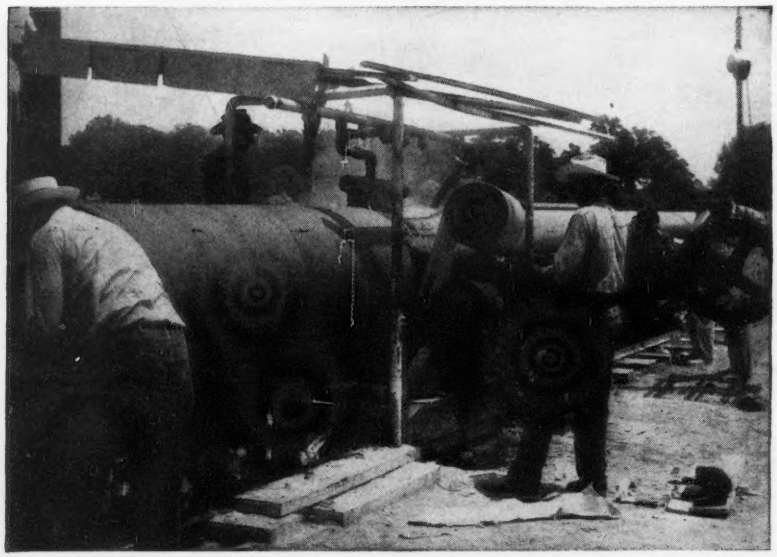
A silver chloride reference electrode being tested by the Navy shows promise, the speaker said. The anodes are installed permanently at appropriate (1)42—8 pt. O. S. 13.5 picas solid .... places on the hull and used as a means of checking the effect of cathodic protection. A system has been devised whereby a signal from these anodes is used to automatically adjust the output of rectifiers supplying current to cathodic protection systems on ships.

Insulating Submarine Superstructure

Insulation of the aluminum superstructure of submarines from steel of the hull has proved practical. Plastic barriers have been interposed in the faying surfaces between the metals and examination of one installation after a period of service has shown reduced galvanic corrosion on surfaces adjacent to the juncture. Cathodic protection is not feasible in these installations.

Polyethylene tapes applied according to a stringent Navy specification have proved effective protection for piping exposed to salt water, Mr. Preiser said. Greater thickness is necessary than in applications not subjected to salt water, he said.

Experiments with high purity zinc anodes containing very small amounts of iron show good performance and little blocking from corrosion products, Mr. Preiser reported.



W. D. Robertson Talks on Stress Corrosion at Yale

The April 4 meeting of Southern New England Section held at Hammond Metallurgical Lab. at Yale University was attended by approximately 14 members and guests. W. D. Robertson of Yale spoke on Recent Consideration on the Mechanisms of Stress Corrosion Cracking, confining his discussion to copper-base alloys and describing potential measurements of grains and grain boundaries which he has made with copper-gold and copper-zinc alloys. He said it has been found that in specific corrosive media the grain boundary area may be anodic to the exposed grain surface area, resulting in intergranular corrosion; while in other media no significant difference in potential exists between these areas.

This was the last meeting of the section until fall.

Two Correspondents Are Named for Corrosion

The following have accepted responsibilities as correspondents for CORROSION in the industrial areas indicated:

V. M. Kalhauge, Standard Oil Co. (Ind.), Chicago, Ill. representing Petroleum Production and Pipe Lines.

Leonard C. Rowe, Chemistry Dept., Research Staff, General Motors Corp., Detroit, representing Transportation Industry.

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A. B. Campbell, Executive Secretary
1061 M & M Bldg. Houston 2, Texas

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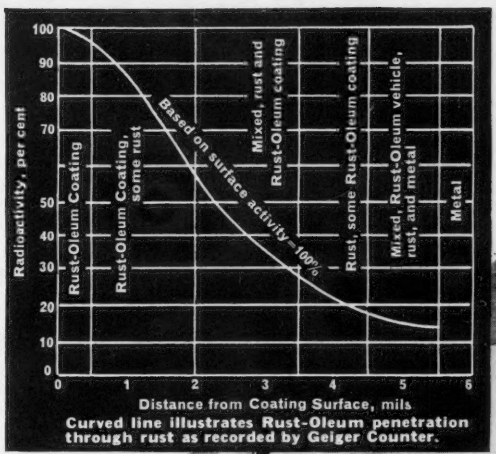

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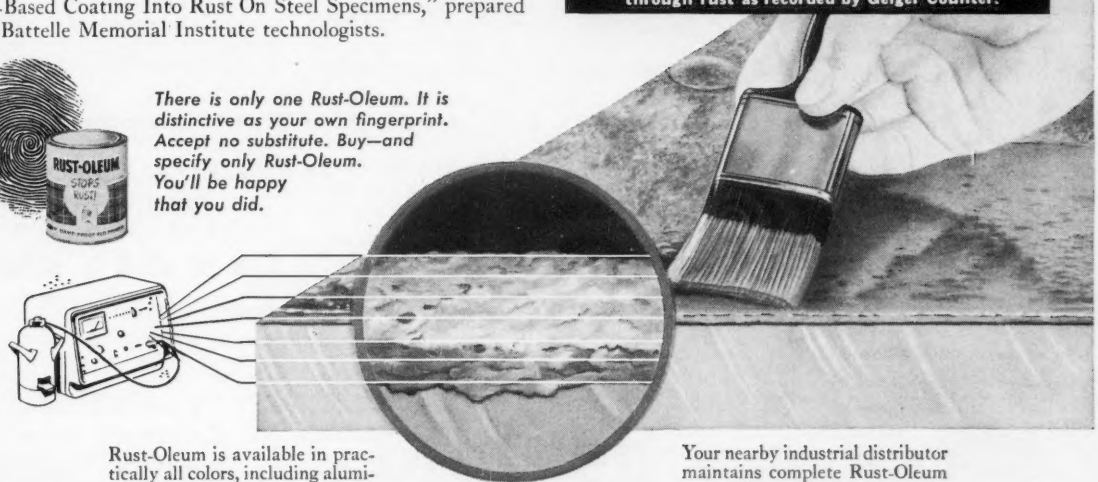

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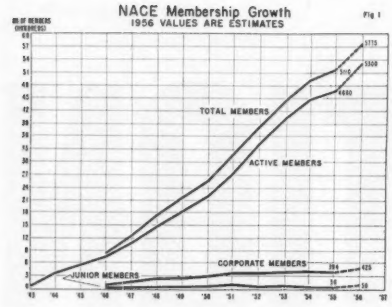
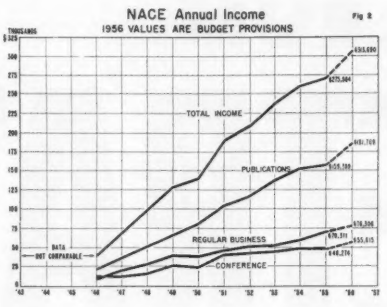
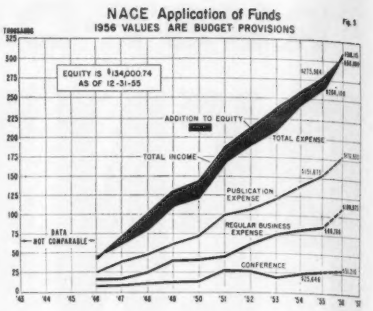






Brannon Points to Liberal 1956 NACE Budget

By R. A. Brannon, Treasurer

During 1955, the financial affairs of NACE continued along the same general pattern as in the past. The rate of increase in number of active members was not as great as in other years. Advertising income also did not increase at its usual rate so that some of the goals set in our budget were not attained.

The number of NACE members is of interest and importance to everyone and especially to the treasury because membership dues are an important source of income. Figure 1 shows the growth in membership since NACE was organized. Many new active members came in during the year, but a fairly large number resigned or were dropped for non-payment of dues. The small but important group of corporate members was increased by 31, but there were 26 resignations for a net gain of five.

NACE receives its income from three principal sources: Publications, regular business and conference. Figure 2, shows the income from each of these sources and their total for each year since 1946 and the estimates for 1956. An error was made in plotting the total income for 1955 so that too great a dip in the rate of increase is indicated. This was discovered too late to have it corrected. The good showing of regular business income resulted from the increase in membership dues which went into effect last year. In preparing the budget for 1956, an effort was made to temper optimism with realism. Much work will be needed to reach these goals. A little extra effort on each one's part in selling advertising and obtaining new corporate members could work wonders in increasing income.

Figure 3 shows where the money was spent. Some of the expense in each category was spent in obtaining income, for instance a big conference expense is space rental for exhibits, a big regular business expense is office rent and supplies while printing, advertising commissions and such make up a large part of the publication expense. Most of the expenses, however, were to provide services to members.

Budget provisions for 1956 expenses are on the liberal side so they exceed budget income by about $4500. While NACE is a non-profit organization, it ought also to be a non-deficit one. This deficit was budgeted to avoid curtailing any worthwhile activities. It is hoped that it can be cured by an increase in income.

The cumulative excess of income over expenses is called Association Equity and was $134,000.74 at December 31, 1955.

A condensed balance sheet is shown in Figure 4. This shows that NACE is in good financial condition.

Balance Sheets as at December 31, 1955, and December 31, 1954, Compared

ASSETS

	December 31, 1955	December 31, 1954	Increase (Decrease)
CURRENT ASSETS			
Cash in Banks and on Hand	$ 27,699.77	$ 32,045.05	($ 4,375.28)
Accounts Receivable			
Members—Corporate	1,100.00	600.00	500.00
Advertising	3,517.50	3,996.61	(479.11)
Reprints	584.06	241.84	342.22
Conference	175.00	375.00	(200.00)
Other	26.21	13.80	12.41
Investments in United States Securities	45,000.00	35,000.00	10,000.00
Inventories of Technical Literature and Abstract Cards	26,339.24	22,370.17	3,969.07
Interest and Dividends Receivable	552.75	718.93	(166.18)
Postage Deposit	30.55	377.22	(346.67)
Total Current Assets	$104,995.08	$ 95,738.62	$ 9,256.46
INVESTMENTS			
Shares in Savings Associations	$ 68,000.00	$ 68,000.00	$
SPECIAL FUNDS			
TP-IG Research Fund Cash in Bank	$	$ 4,098.56	($ 4,098.56)
Educational Fund Cash in Bank	1,426.98	1,435.14	(8.16)
Total Special Funds	$ 1,426.98	$ 5,533.70	($ 4,106.72)
FIXED ASSETS—At Cost			
Office Furniture and Equipment	$ 15,517.18	$ 14,927.73	$ 589.45
Less Reserve for Depreciation	8,826.45	7,379.72	1,446.73
Fixed Assets, Less Depreciation	$ 6,690.73	$ 7,548.01	($ 857.28)
DEFERRED EXPENSES			
Expenses Incurred to December, 1955 (1954) Applicable to Conference of Subsequent Years	$ 4,615.16	$ 3,702.27	$ 912.89
TOTAL ASSETS	$185,727.95	$180,522.60	$ 5,205.35

LIABILITIES AND ASSOCIATION EQUITY

	December 31, 1955	December 31, 1954	Increase (Decrease)
CURRENT LIABILITIES			
Accounts Payable	$ 255.65	$ 166.45	$ 89.20
Federal Old Age Benefit Taxes	171.50	133.04	38.46
Federal Income Tax Withheld from Payroll	1,304.30	1,100.28	204.02
Accrued Advertising Commissions	274.50	12.00	262.50
Total Current Liabilities	$ 2,005.95	$ 1,411.77	$ 594.18
AMOUNTS RECEIVED IN ADVANCE			
Dues of Active Members, Applicable to Subsequent Years	$ 8,746.50	$ 15,786.25	($ 7,039.75)
Dues of Corporate Members, Applicable to Subsequent Years	8,300.00	8,600.00	(300.00)
Exhibitors Space Rentals for 1956 (1955)	9,289.75	7,145.50	2,144.25
Magazine Subscriptions	3,591.90	5,025.75	(1,433.85)
Total Amounts Received in Advance	$ 29,928.15	$ 36,557.50	($ 6,629.35)
REVENUE DEFERRED			
Dues—Corporate Members	$ 9,047.51	$ 8,229.33	$ 818.18
Subscriptions to Magazine "Corrosion"	5,718.62	3,067.33	2,651.29
Advance Payments for Abstracts	3,600.00	3,600.00	
Total Revenue Deferred	$ 18,366.13	$ 14,896.66	$ 3,469.47
CONTRIBUTIONS FOR RESEARCH AND EDUCATIONAL PURPOSES			
Research	$	$ 4,098.56	($ 4,098.56)
Educational	1,426.98	1,435.14	(8.16)
Total Contributions for Research and Educational Purposes	$ 1,426.98	$ 5,533.70	($ 4,106.72)
ASSOCIATION EQUITY—Exhibit C	$134,000.74	$122,122.97	$ 11,877.77
TOTAL LIABILITIES AND ASSOCIATION EQUITY	$185,727.95	$180,522.60	$ 5,205.35

Economic Data Given on Protection of Pipe Lines

Cathodic protection alone of bare pipe is effective and less expensive for the first 15 years than reconditioning, coating and application of cathodic protection to supplement coating, according to O. L. Entrekin, Pure Transportation Company. Mr. Entrekin presented a paper "Survey of Pipeline Coating Practices and Protection Costs," in the absence of D. C. Glass, also of Pure before 55 members and guests of Chicago Section March 20.

The paper included extensive data on protective measures used by 28 leading pipeline companies, reporting the miles of pipe laid during 1930-55, type of protective coating used, if any; percent of total line length protected by coating and/or cathodic protection, cost of coating materials and application cost, average cost of power for cathodic protection by rectifier, estimated cost of protection by galvanic anodes on a per mile basis and effectiveness of cathodic protection as indicated by leak experience.

R. B. Janote of Swift and Co. was master of ceremonies. H. A. Palmer was senior host, assisted by John Gee for the Tar Products Division, The Koppers Company sponsor of the fellowship hour.

A slate of officers was presented for balloting at the April meeting.

Vancouver Section

Vancouver Section participated in a joint meeting with Chemical Engineering Division, Chemical Institute of Canada and American Society for Testing Materials on March 29 at Hotel Georgia Ballroom, Vancouver. Talks were made by R. J. Painter, ASTM executive secretary; C. H. Fellows, ASTM president.

NACE MEETINGS CALENDAR

May

2 Greater Boston Section. Hotel Beaconsfield, Brookline. Organic coatings, Kenneth Tator Associates.

2 Metropolitan New York Section. Chemists Club, New York City.

3 Pittsburgh Section. Mellon Institute, Oakland, Pa.

8 Houston Section. Picnic.

15 Chicago Section. Chicago Engineers Club, 315 S. Federal St. Use of Plastics to Solve Corrosion Problems in Industry, F. L. Whitney, Jr.

17 Kanawha Valley Section. Huntington, W. Va. Fundamentals of Corrosion, Raymond B. Hoxeng.

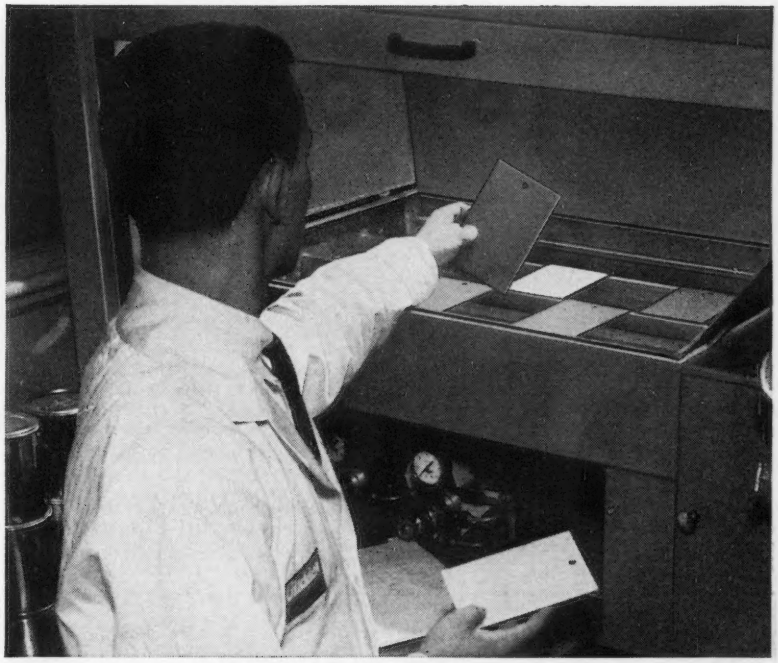
22 Cleveland Section. Hotel Manger, Cleveland. Stress Corrosion, Julius J. Harwood.

24 Sabine-Neches Section. Orange, Texas. Social program.

No date—North Texas Section, annual picnic.

June

12 Houston Section meeting. Chemical treatment of wells. John's Restaurant.



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1957 CONFERENCE COMMITTEE chairmen are shown here at New York. They are, left to right, Charles G. Gribble, Jr., Metal Goods Corp., Houston and Walter B. Meyer, St. Louis Metallizing Company, St. Louis, exhibition co-chairmen; R. T. Effinger, Shell Oil Co., Houston, technical program chairman; W. J. Ries, Tretolite Co., St. Louis, local arrangements chairman and Otto H. Fenner, Monsanto Chemical Co., St. Louis, technical program co-chairman.

•

Alphabetical author indices in the December issue of Corrosion include titles of papers written by or discussed by persons listed.

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Valuable information on new developments of commercial importance may be found in the New Products Section of Corrosion.

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OF ARTICLES PUBLISHED IN CORROSION

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Cathodic Protection and Pipe Lines

Economic Considerations in Pipe Line Corrosion Control by L. G. Sharpe .... .50
Mitigation of Corrosion on City Gas Distribution Systems by A. D. Simpson, Jr. .50
Final Report—Effect of Exposure to Soils on the properties of Asbestos-Cement Pipe by Melvin Romanoff and Irving A. Denison .... .50

Economics

The Cost of Corrosion to the United States by H. H. Uhlig .... .50
Relation of Corrosion to Business Costs by Aaron Wachter .... .50

Inhibitors

Prevention of Corrosion in Cooling Water by R. C. Ulmer and J. W. Wood .... .50
Dicyclohexylammonium Nitrite, a Volatile Corrosion Inhibitor for Corrosion Preventive Packaging by A. Wachter, T. Skei and N. Stillman .... .50

Metallurgical Factors

Resistance of Aluminum Alloys to Weathering by C. J. Walton, D. O. Sprowls and J. A. Nock, Jr., and Resistance of Aluminum Alloys to Contaminated Atmospheres by W. W. Binger, R. H. Wagner and R. H. Brown .50
Laboratory Studies on the Pitting of Aluminum in Aggressive Waters by T. W. Wright and Hugh P. Godard .. .50
Salt Spray Testing Bibliography by Lorraine Voight .... .50
Air Injection for Prevention of Hydrogen Penetration of Steel by W. A. Bonner and H. D. Burnham .... .50
Oxide Films on Stainless Steels by Thor N. Rhodin .... .50
Stress Corrosion Cracking of Hardenable Stainless Steels by F. K. Bloom .... .50

Miscellaneous

Causes of Corrosion in Airplanes and Methods of Prevention by N. H. Simpson .... .50
Corrosion Control by Magic—It's Wonderful by H. H. Uhlig .... .50
Why Metals Corrode by H. H. Uhlig .... .50
Methods of Preventing Corrosion in Sewerage Systems by Ervin Spindel .... .50
Positive Polarity Grounding of Direct Current Supply Requirements in Mining Traction Systems by Sidney A. Gibson .... .50
Prevention of Corrosion in Cooling Water by R. C. Ulmer and J. W. Wood .50
Corrosion Studies on a Model Rotary Air Preheater by G. G. Thurlow .... .50

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Gasoline Resistant Tank Coatings by W. W. Cranmer .... .50
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Symposium on Internal Corrosion of Tankers. Part 3—Corrosion Control in Practice by A. B. Kurz .... .50
Corrosion Control in Gas Lift Wells. II Evaluation of Inhibitors. By D. A. Shock and J. D. Sudbury .... .50
Internal Corrosion in Domestic Fuel Oil Tanks by R. Wieland and R. S. Treseder .... .50

Plastic Materials of Construction

Oilfield Structural Plastics Test Data Are Given .... .50
Service Reports on Oilfield Plastic Pipe .50

San Antonio Meeting's Social Events to Have Historical Settings

"LaVillita," a quaint Spanish village reconstructed in the midst of a modern city will be the scene of the annual banquet and dinner dance of South Central Region this fall. The site, just outside the protective walls of The Alamo, San Antonio's shrine of the Texas Republic, is on the banks of the winding San Antonio river and may be reached by boat—a half-mile trip—or by a three block walk from the hotel.

The October 23-26 meeting will include several other scenic and historic spots in and near San Antonio. Plans for the dinner dance, for example, include presentation of an International Revue preceding a Mexican dinner served on Hidalgo Plaza to the music of Spanish troubadors. The revue will be given in the Arneson River Theater, where performers on the patio-type stage on one side of the river entertain the audience seated on the other side.

Dancing and refreshments on picturesque Juarez Plaza of La Villta also will be available. LaVillita, with its historic Little Church, famous Cos House, Bolivar Building and other structures will be open to NACE members and their ladies.

Plans have been made for ladies to visit the Alamo, the Spanish governor's palace, San Jose Mission, Chinese Sunken Gardens, the original fortifications of old Fort Sam Houston and similar places. Other events are planned also.

If enough registrants evidence interest a field trip to the Southwest Research Institute will be available.

Report Shows NACE Added Four Sections During 1955

By H. C. Van Nouhuys, chairman Regional Management Committee

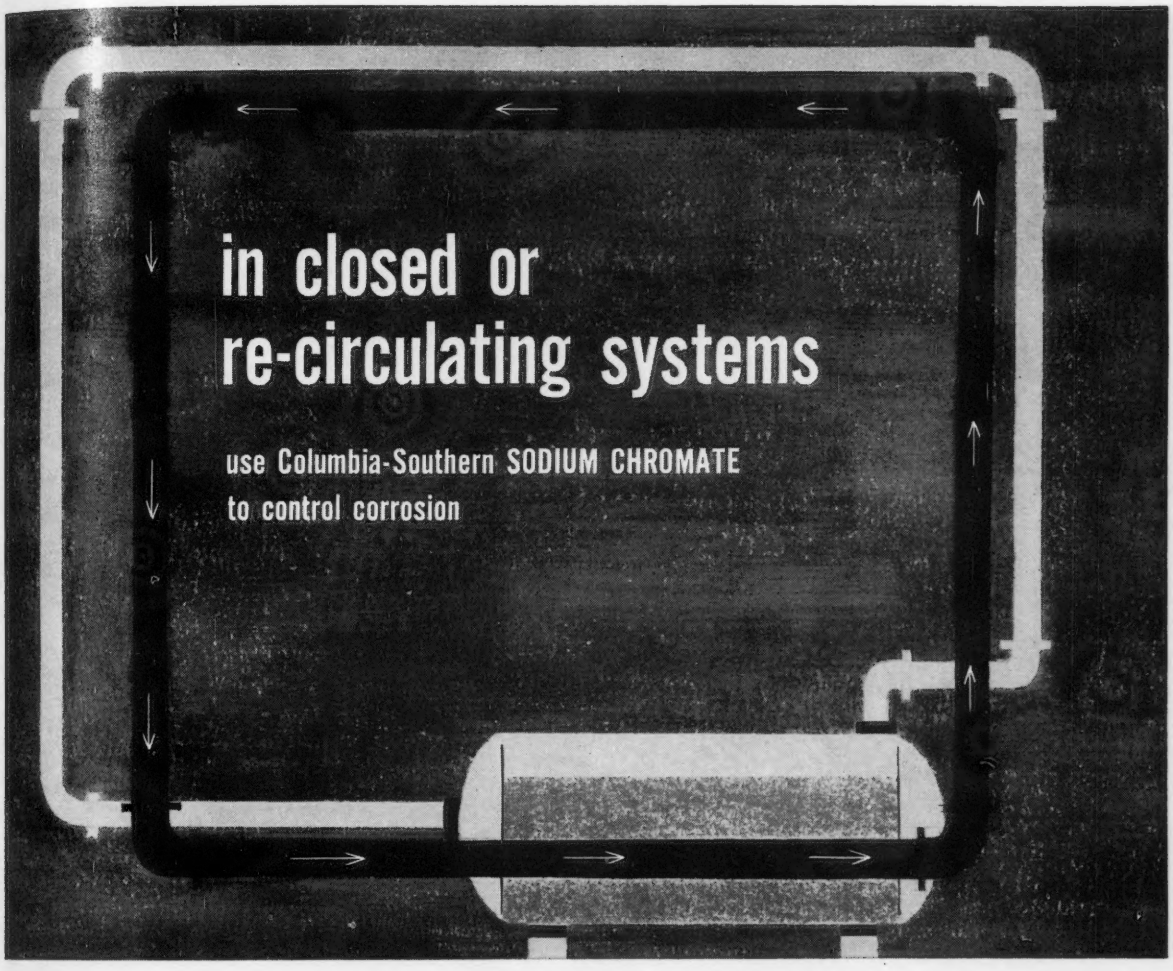
During 1955 NACE continued its healthy rate of growth with the organization of four new sections. The Southeast Region led with two; one at Charlotte, North Carolina, known as the Carolinas Section and the other, the Birmingham Section in Alabama. The Northeast Region gained a new Central New York Section and the North Central Region a Casper Section in Wyoming. This brings the total to 52.

Seven Regional meetings were held this past year with an estimated total attendance of 2000.

Local sections held over 400 meetings with an estimated total attendance of 14,000.

Certificates for Region and Section—past chairman became available from the Central Office during 1955. Certificates will be supplied only upon request of the Region or Section concerned, may be retroactive, cost $7.50 each, and are classed as a non-reimbursable expenditure.

Fifty-four members attended the 1955 Regional Management Committee Meeting in Chicago last year at which the chief subjects of discussion were: organization of local technical practices committees, section financing, certificates for region and section chairman and membership certificates.



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GENERAL NEWS

Report Says De-Icing Salt's Effect on Corrosion is Limited

Corrosion Meetings Abroad Are Listed by Cebelcor

Meetings in Europe at which corrosion matters will be discussed have been listed as follows by Cebelcor:

May 7-8, at Liege—International Meetings for the Study of Water.

May 31-June 2—Meeting of the Society for the Protection of Materials, Zagreb, Yugoslavia.

June 4-9—Sixth International Congress of Mechanical Fabrications. Theme: Surface Preparation to Improve Mechanical Properties and for Protection Against Corrosion, II. Ave. Hoche, Paris VIIIe, France.

June 5-10—Meeting of the Iron and Steel Institute, London.

June 27-July 6—Fifth International Congress of the International Association of Civil Construction, Lisbon.

August 6-7—Symposium on Electrochemistry, Department of Chemistry, Melbourne University, under auspices of the Royal Chemical Institute, Victorian Branch, Inorganic and Physical Chemistry Division.

September 9-16—15th International Congress, International Union of Pure and Applied Chemistry, Lisbon, Division of Chemistry and Chemical Technology, National Research Council, Washington, D. C.

September 17—International Committee for Electrochemical Thermodynamics and Kinetics, Madrid.

November 22-December 3—First European Congress on Corrosion, Paris.

Successful Inhibition of Fuel Oil Corrosion Is Reported

Successful inhibition of the corrosive effect of residual fuel oils burned in gas turbines is reported in an article "Industrial Gas Turbines—Past, Present and Future," by G. R. Fusner, General Electric Review, Page 49, March, 1956. "One method consists of removing most of the sodium from oil and then using magnesium sulfate as an inhibitor. When a residual fuel is so treated and then burned in gas turbines, very little ash is deposited, the corrosion rate is low and a satisfactory life is obtained on the parts that are subject to high temperature," the article says.

Electromotive Series for Molten Chlorides Computed

An electromotive series for solid and molten chlorides has been developed by the National Bureau of Standards, based on thermodynamic calculations using the bureau's SEAC computer. The series gives theoretical electromotive forces for galvanic cells containing 96 different solid and molten chloride electrolytes. The results were published in J. Electrochem Soc., Vol. 103, 8 (1956).

June AES Meeting's Papers Relating to Corrosion Are Listed

Papers to be presented during the June 18-21 43rd Annual Convention of the American Electroplaters Society in Washington, D. C. include the following:

Growth and Properties of Metal Whiskers, S. M. Arnold, Bell Telephone Laboratories, Inc.

Protection of Molybdenum Against High Temperature Oxidation, J. J. Harwood, Office of Naval Research.

Study of Phosphate Treatments for Metal, Lloyd Gilbert, Rock Island Arsenal.

Properties of Electrodeposits at Elevated Temperatures, W. H. Safranek and G. R. Schaer, Battelle Memorial Institute.

Tank Linings, K. G. LeFevre, Metalweld, Inc.

Organic Finishes on Plated Products, G. L. Luthauser, General Motors Corp.

Progress Report on Accelerated Corrosion Tests for the Performance of Plated Coatings (AES Project 15), W. L. Pinner, Houdaille-Hershey Corp.

The Permeation of Gases Through Electrolytic Nickel Deposits as Affected by Accelerated Corrosion, J. Martin Tobin and D. Gardner Foulke, Hanson-VanWinkle-Munning Co.

Japanese Electrochemical Society Journal Publishes Several Corrosion Papers

The Journal of the Electrochemical Society of Japan, 3, 1-chrome, Yurakucho, Chiyodaku, Tokyo, January, 1956, issue No. 1 of Volume 24 includes summaries in English of the principal technical articles published. Subscription rate to overseas non-members is $8 a year.

Included in the January issue among others were: Studies on Analytical Method of Acid Constituents by Means of Electrochromatography (Part 1) Electrochromatography of the Polybasic Acid Radicals, S. Achiwa; Studies on the Electrode Surface (Part 2) Oxide Films on Aluminum (II), by T. Murakawa and Electrical Mechanism of Slow Oxidation of Hydrocarbons by Silent Electrical Discharge (Part 8) Relation Between Slow Oxidation of Hydrocarbons and Ozone Formation Reaction, by E. Inoue and K. Sugino.

To Study Nuclear Problems

ASTM has organized a Special Administrative Committee on Nuclear Problems to consider the activities of the society in connection with the engineering of atomic reactors.

Detroit Committee's Study Covers Autos And Public Utilities

De-icing salt has only limited significance in the corrosion of automobiles and utilities, according to a report issued by the Civic Affairs Committee of the Engineering Society of Detroit. The report summarizes information compiled during a 2½ year study of the problem of corrosion by de-icing salt. Data are presented to show the accelerating effect of salt on automobiles is significant only from the standpoint of appearance and that it is of minor importance in the corrosion of utility structures.

Compared to the economic losses likely from ice-covered streets, however, the committee concludes the corrosion loss attributable to salt is negligible.

Public safety is the primary consideration in the use of salt for de-icing streets. The report concedes salt does have the effect of acceleratng corrosion of automobiles but says "Public safety should transcend all other considerations. Economy of method, effect on automobiles, utilities, etc., though important, should all be subservient to the pressing demand to save lives and property in the urban and rural community."

The city of Detroit spends approximately $300,000 annually for rock salt to spread on streets, some 12,000 to 15,000 tons.

Reports on a study by General Motors on the effect of salt for de-icing on automobiles show that more corrosion is evident on automobiles in cities where salt is used than in other localities. The 5-year study showed that in Detroit 58 percent of cars examined showed corrosion along chrome mouldings while only 35 percent of the same model in Miami showed corrosion at the same spots. A comparison between corrosion suffered by Detroit cars versus cars in New York and New Jersey where no salt was used at the time showed increased failure in the Detroit cars at the fender welt.

The GM study also showed greater failure in gravel deflector surfaces of Detroit cars versus those in places where de-icing salt was not used (1953 data).

Utilities Not Seriously Affected

Glen Coley of Detroit Edison Company is reported to have advised the Engineering Society of Detroit that "the difficulties caused by street salt are not considered too severe." The report says further that "In general, however, the problems of the electric utility are not measurably increased by the use of salt for de-icing streets."

John C. Leffel, Michigan Bell Tele-

(Continued on Page 102)

* The Use of Salt for De-Icing Streets, a report of the Civic Affairs Committee, The Engineering Society of Detroit, 100 Farnsworth Ave.

Responsibility Suggested For Control of Air Pollution

Allocation of responsibility for separate fields of research in connection with control of air pollution has been suggested as follows by W. L. Faith, vice-president and chief engineer of the Air Pollution Foundation:

1—Local government should be responsible for determining the rate and type of emissions of air pollutants from local sources and for monitoring the atmosphere for important contaminants.

2—Federal and state governments should have joint responsibility for determining the relationship between air pollution and public health, for determining the maximum allowable concentrations of air pollutants under various atmospheric conditions and for determining the nature of smog problems which transcend political boundary lines.

3—Each industry should determine the nature of its own emissions, develop control devices, improve its fuels and combustion equipment and support community-wide programs aimed at solving the air pollution problem "beyond its own gates."

4—The community at large (including all segments of business and commerce, industry, government and the public) should provide for coordination of research activities so that no phase of the problem is overlooked, provide also for impartial studies to assess the nature of the local problem and means of alleviating it, and provide for authentic public information "to allay the unfortunate emotional outbursts that so often hinder progress."

AIChE Papers Presented at New Orleans Convention

Among the papers presented during the May 6-9, 1956 Convention of the American Institute of Chemical Engineers at New Orleans were:

Control of Oxygen in Sodium Heat Transfer Systems. I. L. Gray, R. L. Neal and B. G. Coorhies, General Electric Company, Schenectady, N. Y.

Low Cost Materials for Sodium Heat Transfer Systems, R. F. Koenig and E. G. Brush, Knolls Atomic Power Laboratory, General Electric Co., Schenectady.

Static and Dynamic Corrosion and Mass Transfer in Liquid Metal Systems, Leo F. Epstein, Knolls Atomic Power Laboratory.

ASTM Committee Week Developments Are Listed

Included among the developments during the February 29-March 2 Committee Week of the American Society for Testing Materials were the following:

Committee D-1 on Paint, Varnish, etc.: A paper by J. A. Stevens, Dow Chemical Co., on Preparation of Magnesium for Painting.

Two recommended practices for Preparation of Aluminum Alloys for Painting and for Preparation of Magnesium Alloy Surfaces for painting were submitted for publication.

A new Tentative Method for Measurement of Dry Film Thickness of Non-Metallic Coatings on Non-Magnetic Bases was submitted.

Committee B-8 on Electrodeposited Metallic Coatings: A symposium was presented about the tests exposed by Subcommittee II to determine resistance to atmosphere. Program No. 4 of the series on copper-nickel-chromium coatings on steel will evaluate the effect of buffing, use of copper flash, double layers of nickel, etc.

A recommended standard practice for preparing and plating on lead and lead alloys has been developed.

Committee A-5 on Corrosion of Iron and Steel reported that specifications are near on zinc-coated netting and armour wire. Standards on zinc coatings generally are contemplated by this committee.

The committee is considering an exposure test program of hardware specimens at Kure Beach, N. C. and Newark, N. J.

Committee C-22 on Porcelain Enamel, among other things, has initiated a test program to determine the resistance of porcelain enamel to steam and condensate.

Report Says De-Icing—

(Continued from Page 101)

phone Company, is reported as saying that there is little evidence of accelerated corrosion of telephone above-ground equipment as the result of the use of street de-icing salt. Noting that salt finds its way into telephone cable ducts and that it may accelerate corrosion at man holes, the report cites evidence which is said to show that no troubles have been traced by the telephone company to salt in structures not located at points coincident with railway switches or intersections. Mr. Leffel is quoted as reporting that flushing cable ducts seems to be effective in reducing salt concentration and that "the use of salt can increase corrosion, but based on their (Michigan Bell Telephone Company) experience to date, it does not appear that de-icing salts have been a significant factor on telephone structures except at railway switches and intersections."

The report also considers the effect of discharge of brine from salt-melted snow and ice into sewers and streams and the effects of such salt contamination.

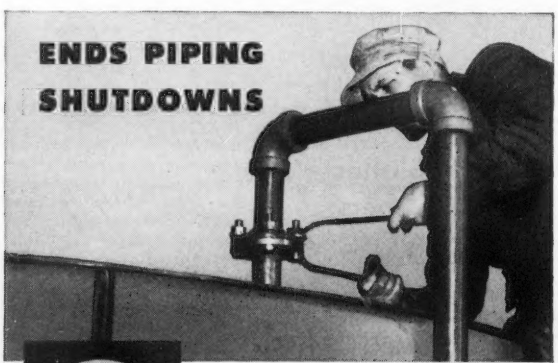
Inhibitors Are Considered

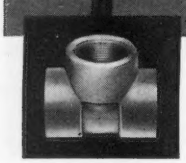
The committee also considered evidence presented concerning the use of inhibitors with salt. Evidence presented tended to show that inhibitors are of doubtful value in protecting the exterior appearance of automobiles but may reduce the weight loss of metals due to corrosion.

The De-Icing Subcommittee of the Civic Affairs Committee of the Engineering Society of Detroit which submitted report consisted of 14 men representing engineering firms, utilities, coatings manufacturers, motor manufacturers and municipal departments.

Creative Thinking Is Theme

Creative Thinking is the theme of the June 4 technical session of the Metals Division Program of the Special Libraries Association Convention at Pittsburgh's William Penn Hotel.





This PVC piping—with injection molded fittings—lasts and lasts

At this plant, unplasticized PVC piping handles sulfuric, nitric, muriatic, phosphoric, and acetic acids. Pressures range to 100 psi. This PVC piping, using Tube Turns Plastics' injection molded PVC fittings, has been in service for months, shows no signs of deterioration. Yet the metal and alloy metal piping it replaced failed at 3 to 12 months intervals from corrosive action. Cut your maintenance—eliminate shutdowns and hazards. Write for free booklet describing properties of unplasticized PVC fittings and flanges. Tube Turns Plastics, Inc., Dept. G5, 2929 Magazine Street, Louisville 11, Kentucky.

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BOOK REVIEWS

Electrochemical Behavior of Vanadium. By E. Deltombe, N de Zoubov and M. Pourbaix. In French. 26 pages, 8 figures, 8¼ x 11¾ inches, paper. January, 1956. Centre Belge D'Étude de la Corrosion, 21 rue des Drapiers, Bruxelles. Price not indicated.

The paper, identified as Report No. 29, consists of a critical examination of the characteristics of the system VH_2O at 25 degrees C. Equilibrium diagrams are given. Thirty-eight references and eight figures are included. This is an extensive mathematical investigation of the system.

•

Cathodic Protection. 74 pages, 8½ x 11 inches, paper. 1954. Published by Society of Chemical Industry, Corrosion Group. Price not indicated.

Six of the seven papers presented at the November 13, 1953 symposium on cathodic protection held at the Institution of Electrical Engineers, England. The discussions to these papers are included also.

All papers and discussions were published earlier in the periodical CHEMISTRY AND INDUSTRY during 1953 and 1954.

•

Major Activities in the Atomic Energy Programs, July-December, 1955. 6 x 9 inches, cloth. January, 1956. United States Atomic Energy Commission. Available from U. S. Government Printing Office, Superintendent of Documents, Washington 25, D. C. Per Copy, 60 cents.

This is the semi-annual report to Congress by AEC. It includes an account of U. S. participation in the International Conference on the Peaceful Use of Atomic Energy and a summary of major activities in the atomic energy program in the United States. Among other things it includes a list of AEC-owned patents available for license.

•

Finishing Handbook and Directory, 1956. 489 pages, 5½ x 8¾ inches, flexible. Edited by I. S. Hallows. January 1956. Sawell Publications, Ltd., 4, Ludgate Circus, London, E. C. 4. Price includes 12 issues of periodical PRODUCTS FINISHING. Per copy, 37s/6d plus postage 7s/6d.

This is the sixth edition of this combined reference book and manufacturers' directory. Added in this edition are sections, cures for faults in electroplating baths, treatment of electroplating wastes, chief finishing specifications and books on finishing subjects. Main directory section of 188 pages is thumb indexed.

•

6th Biennial Corrosion Tour. 62 pages, 8½ x 11 inches. paper. 1956. Edited by Harold S. Winston and John C. Watts, Jr. Copies available from Roscoe Jarmon, Cardinal Chemical Co., Box 2049, Odessa, Texas. Per Copy, $3.

This is a report on the Sixth Biennial Corrosion Tour sponsored by Permian Basin Section NACE. The book includes talks by persons at discussion sessions, a map showing the area covered by the tour, descriptions and comments on the exhibits included in the tour. Exhibits included plastic piping, tanks, combustion units, internally coated flow lines, inhibitor injectors, salt water disposal systems, cathodic protection installations on casing, various kinds of protective coating systems, concrete lined pipe and numerous other oilfield structures.

•

Chemistry of Paints. Vol. 1—662 pages; Vol. 2—643 pages, 6 x 9⅜ inches, cloth. In French. 1956. Edited by G. Champetier, H. Rabate and J. L. Rabate. Published by Dunod, 92 Bonaparte St., Paris, France. Prices, per volume, 5400 F.

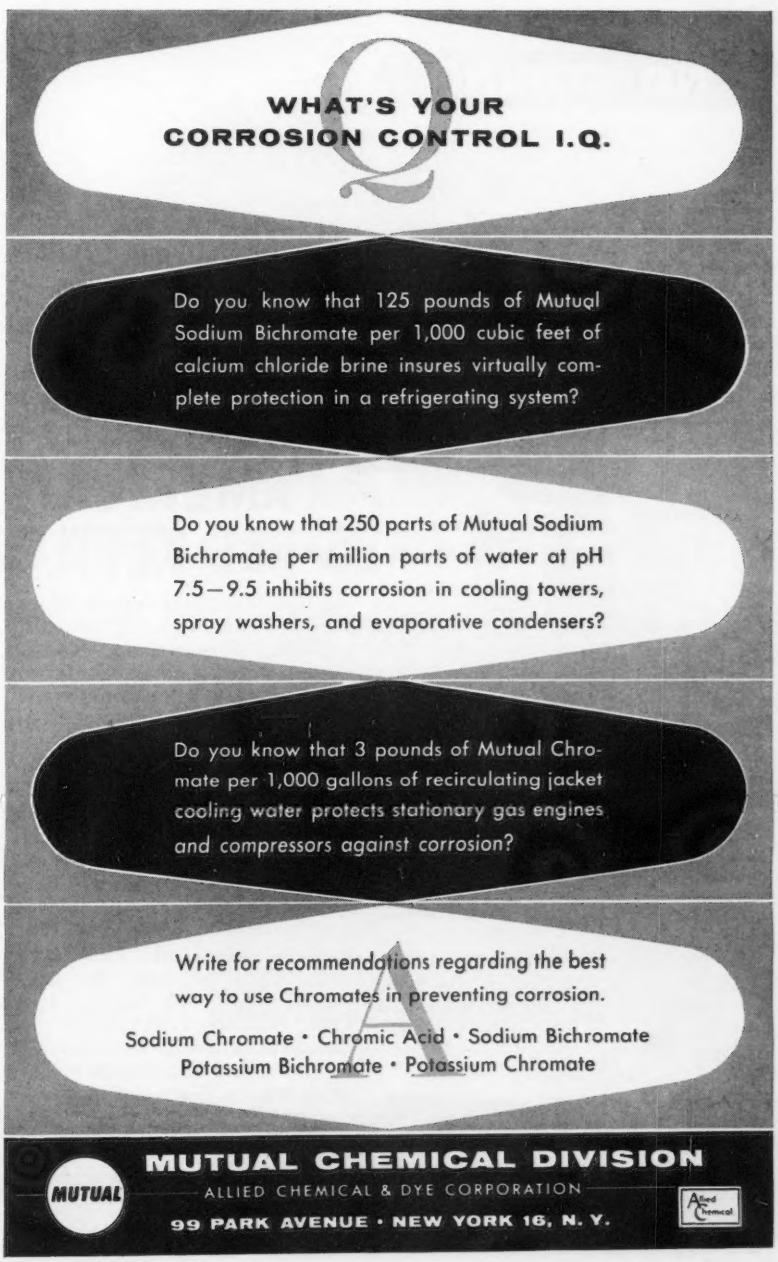
The volumes are essentially an encyclopedia of information on the scientific and technical achievements of the French painting industry. General information and specific developments in the industry during the past 20 years are discussed with the assistance of numerous specialists in the areas covered.

The chemistry and other interesting characteristics of materials used in paints, including molecular schemes, are included in diagram and tables. Each chapter is referenced.

Diagrams and photographs of equipment, techniques and processes used in obtaining raw materials and producing paints and their constituents are covered. Characteristics of organic coloring materials and pigments are discussed, metallic and mineral pigments and solvents also are detailed.

Chyle Elected by AWS

John J. Chyle, Director of Welding Research, A. O. Smith Corp., has been elected president of the American Welding Society.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CORROSION CONTROL I.Q.
Do you know that 125 pounds of Mutual Sodium Bichromate per 1,000 cubic feet of calcium chloride brine insures virtually complete protection in a refrigerating system?
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Corrosion Institute Set May 16-18 by Wisconsin U.

A Corrosion Institute will be held May 16-18 at the University of Wisconsin, Department of Engineering, Madison, Wisconsin.

Committments on the program have been received as follows:

J. F. Ploederl, Wisconsin Protective Coating Co. will speak on Protective Coatings.

F. W. Nelson, A. O. Smith Corp., will speak on Corrosion Proofing by Ceramics.

Walter B. Meyer, St. Louis Metallizing Co., will speak on Metallizing as a Corrosive Preventive. He also will give a case history on the use of metallizing.

Harold F. Haase, consultant, Milwaukee will be a member of a panel on Testing Methods and Evaluation with W. J. Cotton, W. J. Cotton Laboratories, Milwaukee, among others.

Numerous other subjects are scheduled for discussion.

ASTM Silicone Program

The Chemical Properties and Applications of Silicones will be the topic of the 1956 Marburg lecture to be given during the June 17-22 meeting of the American Society for Testing Materials at Atlantic City, N. J. Charles E. Reed, general manager, Silicone Products Dept., General Electric Co., Waterford, N. Y. will be the lecturer.

The Gillett Memorial Lecture will be given by D. K. Crampton, director of development, Chase Brass and Copper Co., Waterbury, Conn. on the subject "Structural Chemistry and Metallurgy of Copper."

The meeting will have 31 sessions including eight symposia including one on pH measurement. Individual papers will be given on metals, fatigue and general testing.

Ocean-Based Automatic Weather Station Developed

An ocean-based automatic weather station that broadcasts weather reports by radio for distances in excess of 800 miles has been developed by the National Bureau of Standards under the supervision of P. D. Lowell, W. Hakkarinen and L. M. Allison. The station translates information of five weather sensing elements into 3-letter groups in Continental code and transmits the coded signals on a pulse-modulated carrier frequency of 6 megacycles.

Tin Research Is Underway

Extensive inquiries are under way by the Tin Research Institute into the resistance to corrosion of tin coatings in cans, galvanic relationship of tin to other metals, packaging of tin coated materials and filamentary corrosion. These and other activities of the institute are reported in the 1955 Annual Report, International Tin Research Council, Tin Research Institute, Fraser Road, Greenford, Middlesex, England.

Air Pollution Expenditures

Planned expenditure of about $1,750,000 by Southern California Edison Company over the next two years to reduce the emission from its power plants of sulfur dioxide and contaminants resulting from burning high sulfur fuel, is reported by Report, March, 1956 issue, a periodical published by the Air Pollution Control District, County of Los Angeles.

Subject Matter Outlines

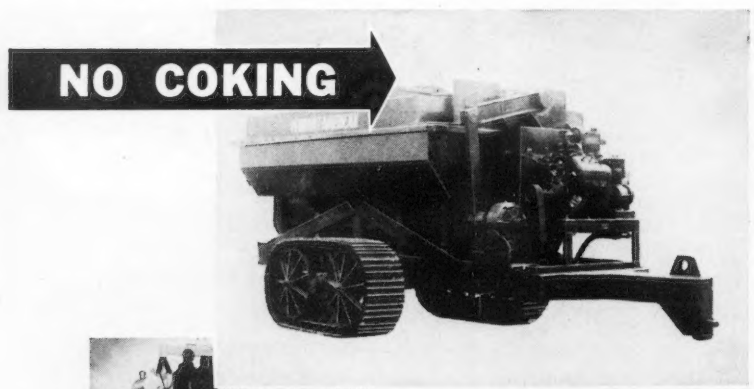
Microfilm or photostat copies of classified outlines of subject matter collected by the Special Libraries Association are expected to be available soon from the School of Library Science, Western Reserve University, Cleveland 6, Ohio. A loan collection of such systems is maintained by the association which solicits classifications to be included.

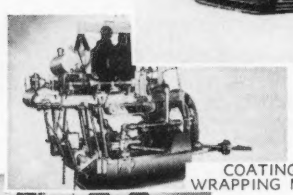
Paint Testing Principles

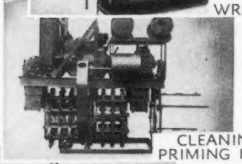
A. C. Elm, New Jersey Zinc Co., will present a paper "Principles of Paint Testing" during the May 12 afternoon session of the Southwestern Paint Convention to be held at Dallas May 10-12. The convention will be held in the Statler Hilton Hotel.

600 Megacycle Transistors

Transistors that will operate at frequencies up to 600 megacycles have been developed by Bell Telephone Laboratories, according to the Industrial Research Newsletter, Armour Research Foundation.



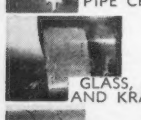

COATING AND WRAPPING MACHINES


CLEANING AND PRIMING MACHINES

PNEUMATIC-TIRED LOWERING-IN CRADLE

PNEUMATIC-INSIDE LINE UP CLAMP

PIPE CRADLES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AND: PATCH POTS, BURNERS AND ACCESSORIES. TONGS, SLING BELTS, AND HOOKS, LINE-UP CLAMPS. HAND TOOLS. SUPPLIES AND EQUIPMENT OF EVERY SORT.

PERRAULT-AMERICAN 25 BBL KETTLE

Agitator mat bars scrape entire kettle bottom every 3.35 seconds, allowing no material to remain on bottom long enough to burn, eliminating coking completely. Mat motion is slow enough so dope is not "whipped." Heavy mat will not float, scrapes bottom thoroughly.

OTHER FEATURES: Actual capacity is 25 bbl.-plus; Completely insulated; Melts dope fast; Drain valve inside kettle requires no pre-heating; Burner gravity-fed, no pump required; Fuel is diesel oil; Fuel tank capacity is 50 gals. Perrault-American 25 bbl. Kettles give contractors the most economical, rapid, maintenance-free-and-easy service. Other sizes available. For more information write or phone.

PERRAULT EQUIPMENT COMPANY

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Equipment Services NEW PRODUCTS Materials Literature

Water-Skipper, an aerosolized water repellent, is manufactured by the Textile Adjuncts Corp., 876 Pacific St., Brooklyn, N. Y. The product, when applied to porous materials, manufacturers say, produces a non-sticky hydrophobic coating. On non-porous surfaces it acts as a neutral and non-plastic waterproofing agent. The material is said by the manufacturer to contain organic silicones, a tung oil derivative, some wax-like water repelling compounds, a non-toxic gas carrier (Freon) and some hydrocarbon solvents.

•

Lime Scale and Rust removal with Oakite Compound No. 32 is described in a folder available from the company at 19 Rector St., New York 6, N. Y.

•

Koppers Company has begun full scale production of polyethylene at its Port Arthur plant. The plant has a rated capacity of 18 million pounds annually.

•

Nickel and High-Nickel Alloys for Pressure Vessels, being Bulletin No. 24 published by the Welding Research Council of The Engineering Foundation is now available through The International Nickel Co., Inc., Reader Service Section, 67 Wall St., New York 5, N. Y.

•

Polyken No. 940, an improved polyethylene tape coating for fittings and irregular shaped contours is now available. It was designed specifically for application to ells, valves, fittings, T-joints and general use on in-plant pipe.

•

Luncor Valves and Fittings, a circular describing the PVC valves made by Lunkenheimer, Cincinnati 14, Ohio, is available on request.

•

Ventrijet, a wet dust collector, mixes water, air and dust so that dust particles are transferred from air to the water particles and then impinged at high velocity on special surfaces in the discharge chamber. The collector is manufactured by Pangborn Corp., Hagerstown, Md.

•

Activated Carbon's use in laboratories is explained in a technical data pamphlet available from Barnebey-Cheney Co., Cassady at 8th Ave., Columbus, Ohio.

•

Monsanto Technical Review, Volume 1, No. 1, Spring, 1956, a new periodical published by Monsanto Chemical Company, St. Louis, contains technical articles about materials and processes developed by Monsanto. Articles published are reprinted from technical journals in which they appeared originally. Next issue of the magazine is scheduled for the fall. Availability is not indicated.

Atomic Energy, a new Soviet journal in English translation published by the Academy of Sciences of USSR will be translated by Associated Technical Services. Material will include articles on atomic physics, power generation, raw materials, application of radioisotopes and safety measures. The publication will appear six times yearly. More information can be obtained from Associated Technical Services, P. O. Box 271, East Orange, N. J.

•

Acanal Intermediate primer, designed for application over wash primers and before application of vinyl finish coats are available from The Garland Company, 3748 East 91st St., Cleveland 5, Ohio. Improved adhesion on problem surfaces is claimed.

•

Tay Holbrooke, Inc., 156 Eighth St., San Francisco, has been named distributor for Tapecoat Company in Northern California and Palmer Supply Co., 222 Westlake Ave. North, Seattle, will handle sales and services in the Northwest.

•

Rowe Products, Inc., is the new name of Rowe Paint and Varnish Co., Inc., Niagara Falls, N. Y.

•

Kaiser Aluminum mill products and services are described in a 24-page book-

(Continued on Page 106)

BUY NICOLET

The HIGH ASBESTOS CONTENT Felt

- NICOLET STANDARD—Perforated or Unperforated
- NICOLET TUFBESTOS—(Lightweight)
- NICOLET REFLECTO—(White)

All Glass Strand Reinforced

BEST PROTECTS ENAMEL COATINGS

EASILY APPLIED

Asbestos is *inorganic.* We believe this *inorganic* material, which comprises the major contents of the base felt, provides a longer-lasting shield protection for all pipeline enamel coatings.

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Photo showing Nicolet Felt Protecting Pipeline

The Felt With a Future

MANUFACTURED BY:
NICOLET INDUSTRIES, INC.

70 PINE STREET
NEW YORK 5, N. Y.

NEW PRODUCTS

(Continued from Page 105)

let available from Kaiser Aluminum & Chemical Sales, Inc., Industrial Service Division, 1924 Broadway, Oakland 12, Cal.

•

135 Ni-o-nel electrode and 65 Ni-o-nel filler wire and rod have been developed at the Bayonne Research Laboratory of the International Nickel Company for welding Ni-o-nel nickel-iron-chromium alloy.

•

Conductivity of solutions can be controlled with an accuracy of plus or minus 0.5 percent of full scale by a new electronic instrument developed by the Fielden Instrument Division of Robertshaw-Fulton Controls Company, 2920 North Fourth St., Philadelphia 33, Pa. It is equipped with action for both alarm and control. A single set-point knob on the front provides control within the range of the instrument calibration.

•

Alkaserts, plastic sleeves designed for insertion in condenser tube ends to limit corrosion resulting from turbulence are manufactured by Metals and Plastics Division of Imperial Chemical Industries, Ltd. They are distributed in the United States by C. Tennant Sons & Co. of New York, 100 Park Ave., New York 17, N. Y. The type of plastic is not specified, but the inserts are reported to soften at temperatures over 70 C and to melt at 110 C.

•

Liquid Chlorinated polyphenyl is the base for a new series of paste pigments developed by Chemical Sealers, Inc., Belleville, Ill. Manufacturers claim sealing and surfacing paints and varnishes made with the new material are non-oxidizing, non-corrosive, non-inflammable and non-hygroscopic. A solid waterproof barrier is formed which blocks moisture completely for an indefinite period. It is claimed also that the paint when applied to ship hulls is toxic to barnacles.

•

Valves injection molded of polyvinyl chloride and including Teflon bearing buttons are being manufactured by Tube Turns Plastics, Inc., Louisville, Ky. They are available in 1, 1½, and 2-inch sizes to match pipe of corresponding nominal size.

•

Herculite, a fabric of unspecified content, is said by the manufacturers, Herculite Protective Fabrics, Inc., 140 Little Street, Belleville, N. J., to have greater tear strength in respect to weight than most fabrics designed for similar service. The material also is reported to have excellent resistance to lubricating oil, acids and alkalis.

•

Activated Carbon filters were used to filter ventilation air entering the section of a plant handling photosensitive aluminum. Sulfide gases from the surrounding industrial neighborhood were causing severe damage to the plates before the ventilating system was installed. Connor Engineering Corp., Danbury, Conn., produces the filters.

•

Stop Internal Corrosion, a 4-page brochure of Cook Paint and Varnish Co., Box 389, Kansas City, Mo., describes the firm's products designed for coating the interior surfaces of pipes and tanks. One coat application is said to protect surfaces against corrosives, including sulfide crudes. The coating also eliminates scale and paraffin deposition, manufacturers say.

•

Thin Walled tubes are used to form O-rings useful in making joints tight against corrosives, according to The Advanced Products Co., North Haven, Conn. They are described in a brochure titled "For Positive Static Sealing" available from the company.

•

Gold-Colored, non-fading aluminum is being made in a variety of shades and tones by Kaiser Aluminum & Chemical Corp. The color is formed by anodizing under controlled conditions so that the surface assumes a gold color. Tests simulating years of sun exposure produced no changes perceptible to the eye, making it substantially more sunfast than the best known color anodic applications used heretofore. The coating is said to increase the resistance of the aluminum to corrosion and wear. It withstands boiling water temperature without color loss.

•

Radiant Heating Construction, a report by the Engineering Service Dept., A. M. Byers Co., Box 1076, Pittsburgh, was designed to help architects and engineers interested in radiant heating systems. A copy can be obtained on application to the company.

(Continued on Page 108)

NOW...for the first time measure corrosion DIRECTLY!

THE CORROSOMETER*

Quick, Convenient, Accurate. Now you can measure progress of corrosion at any location in your system or plant—without need for handling test coupons, taking samples or disturbing plant operations!

The Corrosometer system consists of any number of probes which remain in continuous service, and a portable meter which simply plugs into each probe to indicate extent of corrosion directly in micro-inches of metal lost.

Corrosion measured takes place on the specimen built into the probe.

Probes are available in many different constructional alloys to meet various processing requirements and systems in chemical plants, food plants, refineries—wherever corrosion is a problem. *To get the facts on how to boost corrosion control efficiency and cut your costs with the Corrosometer, write direct today for full details!*

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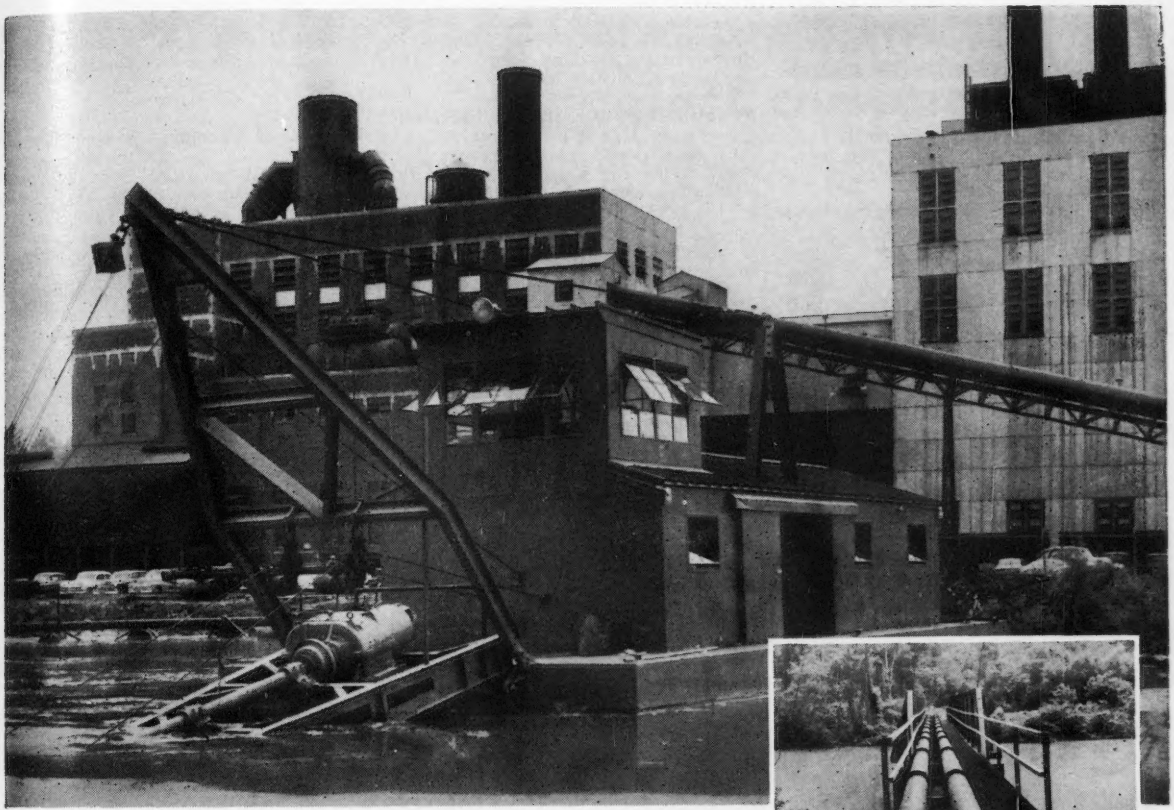

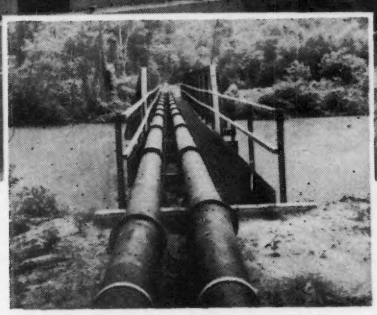

American Double-X Mechanical Joint Pipe was laid over this canal on a bridge.

Over a canal, under a river, into a lake...

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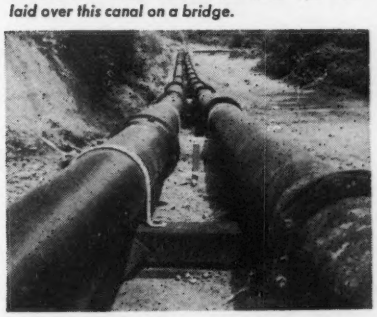
Mix ashes and water and you get an abrasive slurry. Push it through ordinary pipe at high speed and you get fast wear...

Ash disposal creates a problem at every coal-fired steam generating plant. American Cast Iron Pipe Company service helped in an unique solution to this problem at one plant.

Here, ashes are discharged from the plant into a small nearby lake for temporary storage. A floating hydraulic dredge on this lake then pumps the mixture of ashes and water through American Pipe to another lake for permanent storage. This lake, built in a hollow which will provide adequate storage space for twenty years, is retained by a porous dam. Water drains out; ashes remain.

The American Pipe used in the land lines of this installation is heavy wall, abrasion-resistant alloy cast iron pipe with Double-X Mechanical Joints. For the river crossing, Molox Ball Joint Pipe was used.

There is an American Cast Iron Pipe designed for your exact purpose—long-lasting, economical, trouble-free pipe. Specify *quality* pipe, centrifugally cast—American Cast Iron Pipe.



These 12-inch Double-X lines, conducting a mixture of ashes and water to a storage lake, connect to Molox Ball Joint Lines laid under a river.

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BIRMINGHAM 2, ALABAMA

SALES OFFICES
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Los Angeles / San Francisco
Pittsburgh / Cleveland
Seattle / Denver

NEW PRODUCTS

(Continued from Page 106)

Flex-Seal Centrifugal pumps, said by Bart Laboratories, 225 Main St., Belleville, N. J., to have almost twice the capacities and head pressures of pumps of equal size and horsepower have been developed for handling corrosives. They are made wholly of stainless steels.

•

Woodbridge Township, Middlesex County, N. J., will be the site of a new 30 million pound annual capacity polyethylene plant of Koppers Co., Inc. Production is scheduled in the first quarter of 1957. The material will be marketed under the trade name "Super Dylan" polyethylene. Among other products to be made from it are extruded pipe.

•

Mass Rate of flow of liquids can be measured and controlled with the Electro-Caloric Flow Meter developed by Industrial Development Laboratories, Inc., 17 Pollock Ave., Jersey City 5, N. J. The device, which measures the rate of heat transfer through the boundary layer of liquid, has no elements exposed to the fluid being measured. There is no pressure loss.

•

Homalite 101, a clear thermosetting plastic, providing better thermal insulation than glass and, according to manufacturers The Homalite Corp., 11-13 Brookside Drive, Wilmington 4, Del., insoluble in every known solvent, is available in sheets approximately 24 x 30 inches.

•

High Alloy Assemblies for the Process and Allied Industries, a brochure available from General Alloys Company, Fabricated Alloy Division, 371 West First St., Boston Mass., describes the company's special services for producing high alloy assemblies for the chemical, petroleum, food, petrochemical, pharmaceutical and other process industries.

•

Zinc Controls Corrosion, a 16-mm sound and color motion picture produced by American Zinc Institute is available for showing. Bookings can be made at American Zinc Institute, Inc., 60 East 42nd St., New York 17, N. Y. It describes new continuous galvanizing lines, hot dip galvanizing, cathodic protection, metallizing, Sherardizing and painting.

Jones & Laughlin Steel Corp. has started production on its new $6,250,000 continuous hot-dip galvanizing line at Pittsburgh. It is rated at 7 to 8000 tons of galvanized sheets monthly.

•

Oxides of Titanium are used in a rectifier made by Research Laboratories of Fansteel Metallurgical Corp., North Chicago, Ill. The new plates can be assembled in series, parallel or both or in half-wave, bridge or center tap arrangements in a wide variety of sizes and ratings.

•

Mobile Drill Model B-40, engineered to operate as a core or auger drill, may be adapted for tractors or vehicles or independently driven by a motor mounted at the rear of any vehicle. The hydraulically powered drill may be used with hollow stem augers in hard formations. It can be used for under-road boring or at any angle in 360 degrees. Mobile Drilling Inc., 960 North Pennsylvania St., Indianapolis 4, Ind., will supply further details on request.

•

Nukemite Protective Coatings 24, 33, 40 are described in a brochure available from Nukem Products Corp., 111 Colgate Ave., Buffalo 20, N. Y.

•

T-1 Steel, said to have four times the atmospheric corrosion resistance of structural steels commonly used in buildings, is being used in the construction of a 1379-foot television tower at Nashville, Tenn. Blaw-Knox Company, Pittsburgh, is the erector for General Electric Company, general contractor.

•

International Nickel Company's St. Louis Technical Field Section office is now located at 10 South Brentwood Blvd., St. Louis 5, Mo.

•

Doubled Production of molybdic oxide, currently 2,700,000 pounds a year, will be effected when a second sublimation furnace is installed at its Langeloth, Pa., plant by Climax Molybdenum Company.

•

Texsteam Chemical Injectors, Series 1200 (S beam type) and 3700 (gas driven type) are said to offer advantages over older series by Texsteam Corp., 320 Hughes St., Houston. The injector pump heads now are made of Meehanite castings instead of brass or bronze and all pump packing are of Hycar. The new series handle all compounds customarily used for emulsion breaking or corrosion control injections.

•

Albany Products Co., Inc., Connecticut Ave., South Norwalk, Conn., will specialize in fasteners made of corrosion and heat resistant alloys.

•

Bakelite Epoxy resins available from Bakelite Company, a Division of Union Carbide and Carbon Corp., 260 Madison Ave., New York 16, N. Y., are described in Technical Releases 15 and 16, available on request. The new series, developed specifically for surface coatings, are available in air drying or baking forms applicable by all common methods. Two react with amines, polyamides and urea-formaldehyde resins, one is in solution and the other is a solid resin. Two esterify with vegetable oils.

(Continued on Page 110)

COKE BREEZE
Backfill for Anodes
Ideally suited for use with anodes. Has a high carbon content and comes in ⅛-inch by O size. In bulk or sacks.
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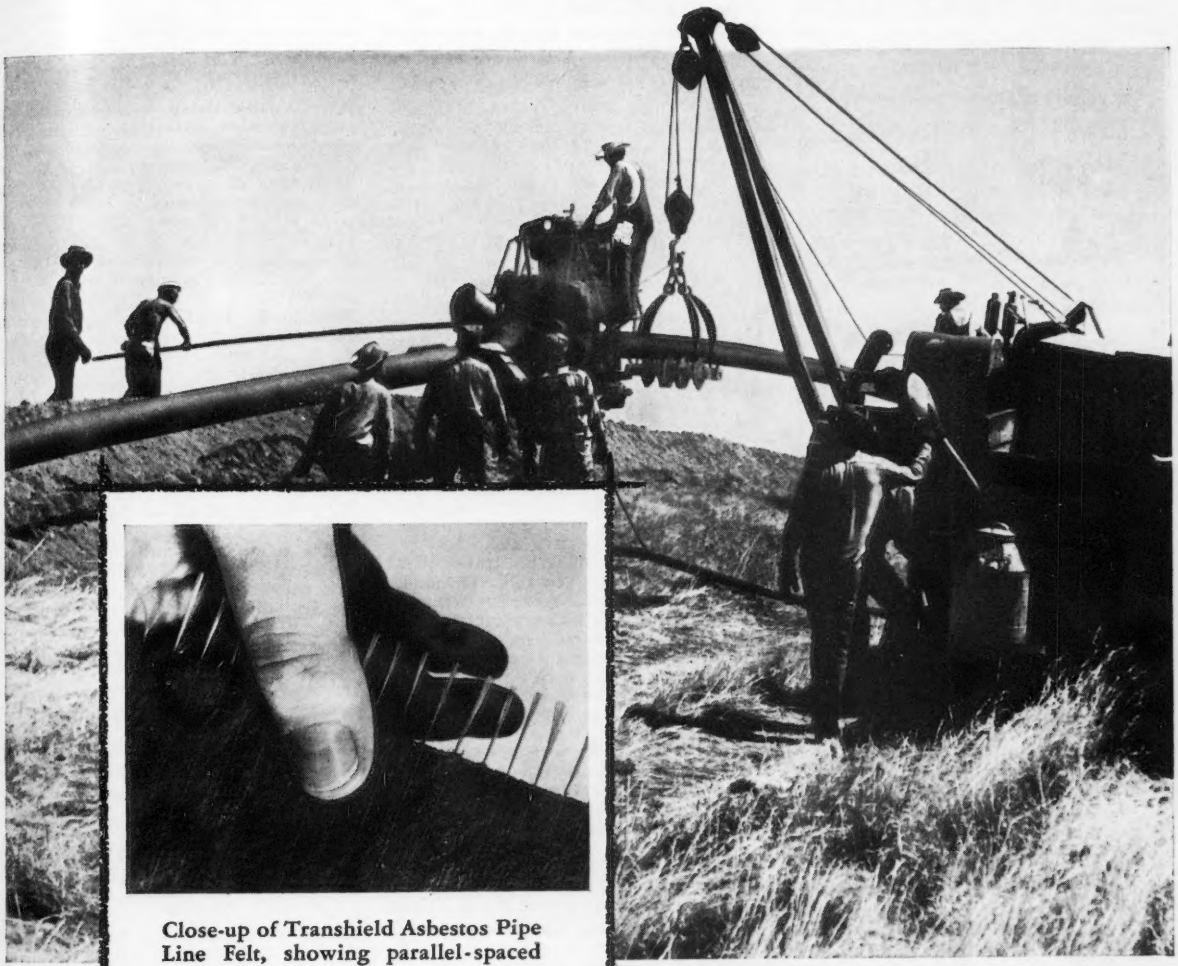

Close-up of Transhield Asbestos Pipe Line Felt, showing parallel-spaced glass yarns.

Coating and wrapping pipe line to check corrosion and assure long-term service.

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Johns-Manville Transhield is an economical pipe line felt assuring effective, long-term protection against corrosion under average soil conditions.

Designed for easy, high-speed application by modern machine methods, Transhield is strong and highly tear-resistant. Its light weight permits its use in 800-ft. rolls. This advantage cuts roll changes in half for field wrapping equipment.

Transhield provides a protective membrane of coal-tar saturated asbestos felt, reinforced with continuous glass yarns parallel-spaced on ¼" centers. It cannot rot or decay, thus acts as an enduring barrier to shield pipe line enamels from earth loads and soil stress.

For severe soil conditions use Johns-Manville #15 Asbestos Pipe Line felt . . . proven in service for over 30 years.

For further information about Transhield, write to Johns-Manville, Box 60, New York 16, N. Y. In Canada, 565 Lakeshore Road East, Port Credit, Ont.

JOHNS-MANVILLE JM PRODUCTS

Johns-Manville PRODUCTS FOR PIPE LINE PROTECTION

NEW PRODUCTS

(Continued from Page 108)

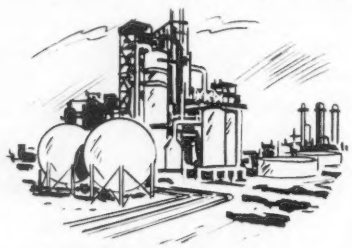
Industrial Piping Division of Grinnell Company, Inc., Providence, Rhode Island, says benefits from a line of new consumable solid insert rings include smoother root pass welds with elimination of root pass cracking and improved weld contours in thin wall piping with one or two less passes.

•

Concrete Gunning Equipment available from Air Placement Equipment Company, 1005 West 24th St., Kansas City 8, Mo., is described in a booklet available from the company.

•

Teflon Tape No. 549, combines the properties of high quality Teflon film with the chemical and heat resistant properties of a pressure-sensitive adhesive. The semi-transparent tape is designed for use in corrosive environments, is unaffected by temperature change within the range—65 to 400 F, with excellent conformability. No significant effect was noted from 7 days' immersion in distilled water, 3 percent sulfuric acid, 40 percent sulfuric acid, 10 percent sodium chloride and 1 percent sodium hydroxide.



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MEN in the NEWS

H. Lloyd Nelson, Director of Market Research, Promotion and Products Scheduling for the United States Pipe and Foundry Co., died in Birmingham, Ala., Dec. 27, 1955 after a short illness. He was 52 years old. As a member of the American Water Works Association, Mr. Nelson served as secretary-treasurer for three sections and was recipient of the Fuller Award. He was also a member of the American Society of Civil Engineers, Federation of Sewage Works Associations, National Society of Professional Engineers and Civitan Club.

•

Andrew R. Spencer, formerly with Steel Sales Corp., Detroit, has formed Precision Testing Laboratories, Inc., at 15329 Schoolcraft, Detroit 27, as a consulting metallurgist and chemist.

•

Kem Meinert has been named head of the new industrial maintenance and corrosion research laboratory at Cook Paint & Varnish Company's main offices in Kansas City. The new laboratory will develop and test heavy duty maintenance finishes.

•

Leslie V. Whiton has opened an office at White Plains, N. Y., for consultation on matters pertaining to the production and marketing of non-ferrous metals. Among other organizations he is a member of NACE.

•

W. D. Kirkpatrick, vice-president and sales manager, American Chain Division, American Chain and Cable Co., Inc., York, Pa., retired March 31 after more than 41 years of service **William B. Ilko** succeeds him.

•

Hal B. H. Cooper is the new director of development engineering for American Potash & Chemical Corp.

•

William A. Hopkins, vice-president of Bart Manufacturing Corp., Belleville, N. J., has been appointed general manager of the Bart Lectro-Clad Division.

•

Joseph H. Duff has been appointed assistant technical manager of Graver Water Conditioning Co., 216 West 14th St., New York, N. Y.

•

A. J. Haagen-Smit of California Institute of Technology has been named head of the air polution control research program of Southern California Edison Company. Initial objective will be to control sulfur products and other gases in stack emissions and reduce the discharge of particulate material.

•

Erick I. Hoegberg has joined American Viscose Corp. as head of its technical information group.

•

Harry C. Burger has been named vice-president of operations of Gates Engineering Co.

•

Herbert Kay has been made manager of catalyst development by Climax Molybdenum Company.

•

Robert P. Ogden is the new plant manager of Sharples Chemical Division's Riverview Works.

•

E. A. Channer has been elected vice-president of H. M. Harper Company, Morton Grove, Ill.

•

Walter R. Wakefield will devote his time to product development and merchandising products of Acorn Paint & Chemical Company, including the firm's anti-corrosion products.

•

W. M. Thornton has been appointed an engineer with Production Profits, Inc., Dallas. The firm's new address is 8912 Sovereign Row, Dallas.

•

John H. Hoff is now hot enamel sales representative in the Tulsa area for Reilly Tar & Chemical Corp.

•

Archibald V. Miegs has been named research chemist for Coast Paint and Lacquer Co., Houston. He will devote his time to product development. He has been an instructor at the University of Houston and is a graduate in chemical engineering from Alabama Polytechnical Institute and Louisiana State University.

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CORROSION ABSTRACTS

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1. GENERAL

1.2 Importance

1.2.5

Investigation of Accident Involving Titanium and Red Fuming Nitric Acid, December 29, 1953. P. M. AMBROSE, J. C. BARRETT, R. W. HUBER, DAVID SCHLAIN AND V. C. PETERSEN. U. S. Bur. Mines Circ. No. 7711, March, 1955, 34 pp. (Abridged version, *Corrosion*, **II**, No. 6, News Section 86 (1955) July.

This report describes an accident which took place in the Chemical Corrosion Laboratory at the College Park, Md., Station of the Federal Bureau of Mines. The accident occurred while Walter L. Acherman, chemist, was performing a routine manipulation during a corrosion experiment involving commercially pure titanium and red-fuming nitric acid. There was a sudden and very violent reaction and a large quantity of acid was thrown in the face and over the body of Acherman, causing serious injury. L. B. Golden, chief of the Chemical Corrosion Section was exposed to nitric acid fumes during the ensuing rescue and first-aid operations and died on January 25, 1954. According to the medical report, the direct cause of Mr. Golden's death was pulmonary edema and confluent bronchopneumonia; the contributary cause was inhalation of fumes from red fuming nitric acid. Data on the behavior of commercially pure titanium in red-fuming nitric acid are summarized. (auth)—NSA. 9929

1.7 Organized Studies of Corrosion

1.7.1

Corrosion Research Laboratories. Part III. The U. S. National Bureau of Standards. J. G. THOMSON. *Corrosion Technology*, **2**, No. 4, 102-105 (1955) April.

Part III. Work done on comparative corrosion of ferrous and nonferrous metals in various environments; efficiency of protective coatings; stress corrosion; current work on basic principles and theories of corrosion—BNF. 9862

2. TESTING

2.1 General

2.1.1,1.2.2

Corrosion. MARS G. FONTANA. *Ind. Eng. Chem*, **47**, No. 2, 81A-82A (1955) Feb.

A nomograph is shown for rapid and ready conversion of corrosion rates into mils per year, inches per month and milligrams per square decimeter per day. The cost of metals and allows is discussed and ratings of various materials are tabulated according to low, medium, high and very high cost.—NSA. 10000

2.2 On Location Tests

2.2.2

Report of Subcommittee VI on Atmospheric Corrosion. H. R. COPSON. *Am.*

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ALL—The Abstract Bulletin, Aluminium Laboratories, Ltd. P. O. Box 84, Kingston, Ontario.

ATS—Associated Technical Services Abstracts, Associated Technical Services, P. O. Box 271, East Orange, N. J.

AWWA—Journal, American Water Works Association, Amer. Water Works Asoc., 521 Fifth Ave., New York 17, N. Y.

BL—Current Technical Literature, Bell Telephone Laboratories, Inc., Murray Hill, N. J.

BTR—Battelle Technical Review, Battelle Memorial Institute, 505 King Ave., Columbus 1, Ohio.

BNF—Bulletin; British Non-Ferrous Metals Research Association. 81-91 Euston St., London NW 1, England.

CBEC—Centre Belge d'Etude de la Corrosion (CEBELCOR), 17 re des Drapiers, Brussels, Belgium.

CE—Chemical Engineering, McGraw Hill Publishing Co. 330 W. 42nd St., New York 18, N. Y.

EL—Electroplating. 83/85 Udney Park Road, Teddington, Middlesex, England.

EW—Electrical World, McGraw-Hill Publishing Co. 330 W. 42nd St., New York 18, N. Y.

GPC—General Petroleum Corp. of California. 2525 East 37th St., Los Angeles 11, Calif.

IIM—Transactions, The Indian Institute of Metals, 23-B, Notaji Subhas Road, P. O. Box 737, Calcutta, India.

INCO—The International Nickel Co., Inc. 67 Wall Street, New York 5, New York.

IP—Institute of Petroleum. 26 Portland Place, London W.#1, England.

JSPS—Japan Society for the Promotion of Science, Address: Mr. Hayata Shigeno, Secretary, Committee of Preventing Corrosion, c/o Government Chemical Industrial Research Institute, 1-Chrome Nakameguro, Meguro-ku, Tokyo, Japan.

MA—Metallurgical Abstracts, Institute of Metals, London, England. 4 Grosvenor Gardens, London SW 1, England.

MI—Metallurgia Italiana, Associazone Italiana di Metallurgia. Via S. Paola, 10, Milano, Italia.

MR—Metals Review, American Society of Metals. 7301 Euclid Ave., Cleveland 3, Ohio.

NALCO—National Aluminate Corp. 6216 West 66th Place, Chicago 38, Illinois.

NBS—National Bureau of Standards. Supt. of Documents, U. S. Gov't Printing Office, Washington 25, D. C.

NSA—Nuclear Science Abstracts. United States Atomic Energy Commission, Technical Information Division, Oak Ridge, Tenn.

PDA—Prevention Deterioration Abstracts. National Research Council, 2101 Constitution Ave., Washington 25, D. C.

RM—Revue de Metallurgie, Paris, France. 5 Cite Pigalle, Paris (9e), France.

RPI—Review of Current Literature Relating to the Paint, Colour, Varnish and Allied Industries, Research Association of British Paint, Colour & Varnish Manufacturers, London. Waldegrave Rd., Teddington, Middlesex.

SE—Stahl Und Eisen, Verlag Stahleisen, M. B. H., Dusseldorf, August-Thysen Str. 1. Postscheck Koln 4110, (22a) Dusseldorf, Germany.

TIME—Transactions of Institute of Marine Engineers. 85 The Minories, London EC 3, England.

UOP—Universal Oil Products. 310 South Michigan Ave., Chicago, Illinois.

ZDA—Zinc Development Association. 34 Berkeley Square, London W.1.

Soc. Testing Materials Preprint No. 101, 1955, 17 pp.

20-year results on 24 non-ferrous metals and alloys, including copper-nickel-zinc alloy, copper-nickel-tin alloy, nickel-copper alloy and nickel, which were exposed to the atmosphere at six locations are tabulated. Locations, including industrial, rural and marine and exposure times are listed. Weight loss and tension data are given. Tables.—INCO. 10210

2.2.2,1.7.2,4.2.2

How U. S. Air Force Tests Planes in Arctic. C. WITZE. *Aviation Week,* **62,** No. 9, 21 (1955) February 28.

Operational tests on weapons systems, including a Martin B-57 twin-jet bomber and all its components and functional evaluation tests on prefabricated buildings, printed circuits, radomes, arctic tie-down gear and a nickel-chromium battery are being conducted by Wright Air Development Center at Ladd Air Force Base, Alaska, 100 miles from the Arctic Circle.—INCO. 9904

2.3 Laboratory Methods and Tests

2.3.2,6.2.5,7.2,1.7.1

Report of Committee A-10 on Iron-Chromium, Iron-Chromium-Nickel and Related Alloys. J. STRAUSS. Paper before 58th Ann. Mtg., Atlantic City, June 26-July 1, 1955. ASTM Preprint No. 7, 1955, 15 pp.

Committee recommends that the Recommended Practice for Acidified Copper Sulphate Test for Intergranular Attack in Austenitic Stainless Steels be accepted for publication as tentative. Committee also recommends revisions of tentatives: Tentative Recommended Practice for Boiling Nitric Acid Test for Corrosion-Resisting Steels (A 262-52T) and Tentative Specifications for Seamless and Welded Austenitic Stainless Steel Pipe (A312-54T). Revision by the addition of the Electrolytic Oxalic Acid Etching Test which may be applied to AISI 304, 316 and 304L, ACI CF-8, CF-8M and CN-7M is covered. Tables and photomicrographs.—INCO. 9857

2.3.2

How Carefully Do You Control Your Salt Spray Tests? H. A. HOLDEN. *Corrosion Technology,* **2,** No. 5, 157-159, 163 (1955) May.

Salt-spray testing, in which specimens or actual articles are contained in a closed cabinet and exposed to the "fog" produced by the atomization of a salt solution, is probably the most widely used method of accelerated corrosion testing in industrial laboratories. Many other salt-spray-testing techniques have been developed and used but this survey is limited to consideration of the so-called "salt-fog" testing method. Criticisms and comparisons of test methods are discussed. Tables.—INCO. 10023

2.3.4,6.3.6

Studies of Egyptian Bronzes. H. WEISZ. *J. Chem. Educ.,* **32,** No. 2, 70-72 (1955) February.

Qualitative analyses of a number of metal statues were made. The eight samples examined were removed by rubbing a microscope slide with roughened section in center across specimen several times. Microchemical technique, named the "ring oven" method by author and which permits analysis of a single drop of solution, is described. Analytical findings are tabulated. Specimens without exception were bronzes. No tin was found in three cases and it is assumed that quantities of tin in these three alloys were below detection limits of test employed. Lead, bismuth and iron were found in seven specimens and zinc was detected in five specimens.—INCO. 9873

2.3.4,4.4.3

Report of Committee D-15 on Engine Antifreezes. H. R. WOLF. Paper before Am. Soc. Testing Materials, 58th Ann. Mtg., Atlantic City, June 26-July 1, 1955. ASTM Preprint No. 48, 1955, 10 pp.

Proposed Tentative Procedure for Glassware Corrosion Test of Metals by Engine Antifreezes is given. In test procedure, specimens of metals typical of those present in automotive cooling systems are totally immersed in the test antifreeze solution for 336 hours at 160 degrees F with aeration. Corrosion-inhibitive properties of test solution are evaluated on basis of weight losses. Metals include steel (SAE 1020), copper, brass, solder, cast aluminum and cast iron. Appendix gives notes on significance and interpretation of the glassware corrosion test. Diagrams and tables.—INCO. 9895

2.3.4, 5.3.2

Some Observations on Assessing the Corrosion Behaviour of Tinplate. W. E. HOARE. Paper before Associazione Italiana de Metallurgia & Tin Research Inst., Conf. on Tin, Milan, September, 1954. *Galvanotecnica,* **5,** No. 11, 256-P (1954); *Sheet Metal Inds.,* **32,** No. 335, 176-178, 188 (1955) March.

Method and the apparatus designed for a study of the possibility of obtaining useful comparative data on the corrosion behavior of various lots of tinplate are described. Procedure involves the simultaneous measurement of hydrogen evolution and electrode potential when a tinplate specimen is attacked by acid. Hydrochloric acid is used as the corroding medium. Graphs and 7 references.—INCO. 10036

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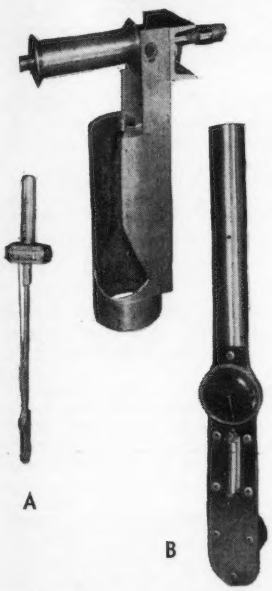
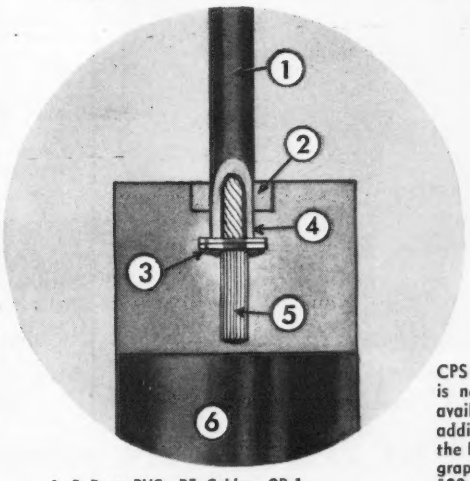


THE Above shows testing devices used on CPS graphite anodes to determine permanency of lead wire attachment. (A) Non-destructive minimum 300 lb. setting wrench. And "Torkflash" testing device developed by CPS to assure quality control of lead-wire attachment, (B) Indicating destructive tester.



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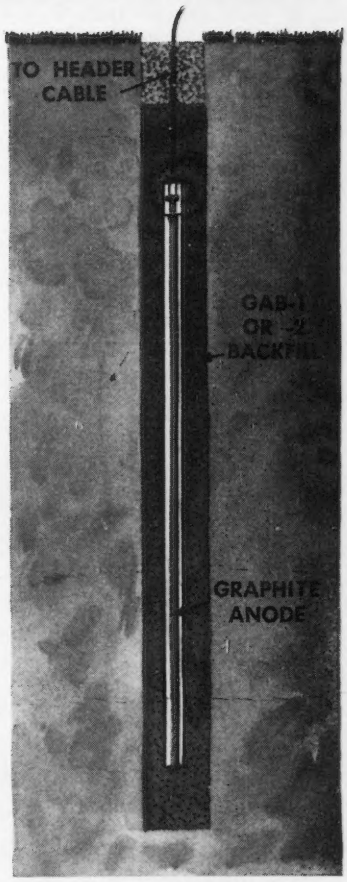

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Scotchrap Tape Coatings
Betzel Tapesters
Maloney Insulating Materials
Erico Cadweld Welding Materials
Fisher M-Scope Pipe and Cable Locators
Detectron Pipe Locators
Wahlquist Pipe Locators
CPS Graphite Anode Backfills
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2.3.7, 5.3.2

Porosity of Nickel Deposits by Autoradiographic Techniques. R. H. WOLFF, M. A. HENDERSON AND S. L. EISLER. *Plating*, **42**, No. 5, 537-544 (1955) May.

Method is described for determining the porosity of nickel deposits by plating nickel over an electrodeposit containing radioactive iron. Nickel films are then evaluated for discontinuities by use of photographic film suitably exposed to radiation emanating through the nickel plate from the iron. Electroless, Watts and phosphorous nickel baths were included in the investigation and autoradiographs obtained were compared with the corrosive effects developed by means of a boil test. Method suggests a new approach to porosity studies that is representative of usual plating conditions. Tables and eleven references.—INCO. 9893

2.3.7, 5.3.2

Metal Film Resistance Thermometers for Measuring Surface Temperatures. C. C. WINDING, L. TOPPER AND B. V. BAUS. *Ind. & Eng. Chem.*, **47**, No. 3, Part I, 386-392 (1955) March.

Surface temperatures are measured by determining the resistance of evaporated films of chromium, nickel, Inconel, silver, aluminum or germanium. Electrical stability, resistance to chemical attack and abrasion resistance of the films were studied; chromium was the most satisfactory. The films have been used to determine film coefficients for condensing organic vapors.—BNF. 9897

2.3.7, 5.3.2, 2.4.3

A Simple Non-Destructive Thickness Gauge for Electrodeposits. A. R. HEATH. *Metal Finishing J.*, **1**, No. 4, 145-150 (1955) April.

The method depends on the fact that different thicknesses of the same metallic coating will conduct different quantities of heat, from a constant temperature heat source, to the boundary between the coating and base metal. The thermoelectric force developed at this boundary can be measured and will thereby provide a measure of the coating thickness. Method is adaptable for rapid routine non-destructive testing and calibration curves have been obtained for the most important commercial plated coatings. Work done by the Brit. Non-Ferrous Metals Res. Assoc.: based on Report R.R.A. 1056 which was issued to BNFMRA members in October, 1954; reprints are available as RRA 1056P.—BNF. 10197

2.3.7, 3.5.8

Determination of Residual Stresses in Lightly Rolled Thin Strip. B. B. HUNDY. *J. Iron Steel Inst.*, **179**, No. 1, 23-29 (1955) January.

Unidirectional stresses may be determined by etching away one face and measuring change of curvature. Method is applied to steel and copper.—BNF. 10050

2.3.7

Reproducibility of Charpy Impact Test. D. E. DRISCOLL. Watertown Arsenal. Am. Soc. Testing Materials Preprint No. 93d, 1955, 5 pp.

To demonstrate that the Charpy impact test is a reproducible test, a special heat of steel cut up to provide 18,000 blanks and heat treated to three energy levels was obtained by Watertown Arsenal Lab. 200 specimens at each energy level were tested in Charpy machines manufactured by two different companies to obtain the deviation and average energy values. Remainder of specimens are being used to check Charpy impact machines throughout the country to determine causes of variations encountered. Charts of results are shown and discussed. Steel specimens contained 0.37-0.385 carbon, 0.75-0.77 manganese, 0.27-0.28 silicon, 0.013-0.015 sulfur, 0.013-0.016 phosphorus, 1.73-1.77 nickel, 0.83-0.86 chromium and 0.25-0.27% molybdenum. Graphs.—INCO. 10032

2.3.9

The Electron Diffraction Camera and High Temperature Corrosion. J. W. HICKMAN, E. A. GULBRANSEN AND R. J. BERTL. *Corrosion Technology*, **2**, No. 4, 116 (1955) April.

Westinghouse Co. has recently developed an electronic camera that contains a tiny furnace and takes pictures of hot metals to aid in the search for new metals and alloys that will withstand rust and corrosion. New instrument uses a high-power beam of electrons to make detailed portraits of metal surfaces as they react to different temperatures, gases and pressures. Its unique 'hair-pin' furnace makes possible close studies of metals while they are being heated to temperatures as high as 2,000 degrees F.—INCO. 10024

2.3.9, 1.4

Bibliography On Industrial Radiology 1952-54. 1955, 24 pp. St. John X-Ray Laboratory, Califon, New Jersey.

Fifth supplement to "industrial Radiology" by Herbert R. Isenburger. It includes references 3021 to 3697. 9888

2.4.3, 2.3.7

Selecting a Holiday Detector. J. RASOR.

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Tinker & Rasor. *Gas*, **31**, No. 3, 127-131, 134, 136 (1955) March.

Steel pipe buried in the ground is subjected to corrosion by galvanic action of the soil. Most effective way of preventing corrosion is by coating the pipe with an electrically nonconducting material such as coal tar or asphalt. Properties of these materials are such that they have high electrical resistance compared to metal pipe on which they are placed. This property makes possible a method of locating faults in application of coating by recording a substantial difference in electrical resistance at any point from surface of coating to the metallic pipe. Several types of holiday detectors, employing varying energy sources and several types of generating systems are covered. Technical aspects of these detectors are discussed. Diagrams.—INCO. 9827

3. CHARACTERISTIC CORROSION PHENOMENA

3.1 General

3.1,5.1

Metal Corrosion and Protection. Parts I, II. R. R. Rogers. *Chem. Can.*, **7**, Nos. 3, 5, 37-38, 38-41 (1955) March, May.

Part I. This paper defines metal corrosion and compares the corrosion rates of aluminum, magnesium and other metals under the same conditions. The corroding agents used were: Sulfuric acid, hydrochloric acid, phosphoric acid, acetic acid, citric acid, sodium chloride and sodium hydroxide, in 10% aqueous solution. The mehanism of electrochemical corrosion is given.

Part II. This part of the article deals with the chemical and electrochemical processes used to prevent corrosion and discusses the merits of laboratory methods used to evaluate corrosion resistance. —ALL. 9909

3.2 Forms

3.2.2.

The Embrittlement of Steel by Hydrogen. W. A. Bell. *Product Eng.*, **26**, No. 3, 189-192 (1955) March.

Hydrogen is soluble in iron and produces defects in steel which destroy the structure of the metal. Effects of hydrogen penetration in steelmaking, in welding, in pickling and plating and during corrosion are covered. Detection of embrittlement and methods for removal of hydrogen are discussed. Graphs.—INCO. 9922

3.2.2,3.5.8

Stress Corrosion Phenomena in Highly Stressed Steels Resulting from Diffused Hydrogen. I. Class. *Werkstoffe u. Korrosion*, **6**, No. 5, 237-245 (1955) May.

Describes the appearance of transcrystalline cracks in ordinary and alloyed heat-treated steels used in high pressure condensation units and laboratory experiments to get these appearances. These cracks are caused by hydrogen resulting from some corrosion taking place on the surface of the steel in the presence of hydrogen sulfide. Hydrogen penetrates into the metal creating high local pressures. Extensive research is being undertaken in the United States in connection with this phenomena appearing in the petroleum industry. Factors influencing these cracks and their growth, stressing the importance of the ductility of the material and preventive measures are discussed.—INCO. 9965

3.2.2,3.4.8

The Pitted-Tank Mystery. M. R. Hyslop. *Metal Progress*, **67**, No. 3, 90-95 (1955) March.

Failure of Type 309 stainless steel (13.5% nickel, 22.5% chromium, 0.20% carbon) retort in an ammonia dissociator was reported after only eight months' service. It was penetrated by pits in upper head starting from outside, some near a weld and others in the smooth plate. After extensive chemical, spectrographic and metallographic analysis and hardness and bend tests, the contaminant was found to be sulfur. Further investigation showed the source of sulfur to be the soap used on pipe joints while the system was pressure-tested. Photomicrographs.—INCO. 10027

3.2.3,3.8.4

Causes of Corrosion. (In German.) H. Grubitsch. *Chem.-Ing.-Tech.*, **27**, No. 5, 287-298 (1955) May.

Reports on tarnish and scale actions in the system metal-gas and thermodynamic treatment of corrosion actions. Diagrams, graphs, tables, 123 references.—BTR. 9990

3.4 Chemical Effects

3.4.2,3.8.4

Catalytic Corrosion. S. Z. Roginskii, I. I. Tret'yakov and A. B. Shekhter. Doklady Akad. Nauk SSSR, **91**, 881-884 (1953); digest: *Metal Progress*, **67**, No. 5, 177-178, 180 (1955) May.

Iron, copper and platinum were used

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as test materials in study of catalytic corrosion during an endothermic reaction, the decomposition of ammonia. Rate of disintegration was highest for iron, followed by copper and platinum. Neither rate of self-diffusion of metal nor amount of decomposition of ammonia could be correlated with degree of catalytic corrosion. It was likely that an iron nitride had formed and that neither copper nor platinum could form a nitride. Authors concluded that compound formation was most probable cause of a high rate of catalytic corrosion. Possible causes of catalytic corrosion were increased mobility of surface atoms of metal as a result of catalytic reaction, increased mobility because of sorption of a gas, such as ammonia or hydrogen, a sorption not connected directly with catalysis, and formation of new phase under conditions of catalysis.—INCO. 10203

3.5 Physical and Mechanical Effects

3.5.3,3.5.8,1.6

Friction, Wear and Surface Damage of Metals as Affected by Solid Surface Films. E. E. Bisson, R. L. Johnson, M. A. Swikert and D. Godfrey. National Advisory Committee for Aeronautics, Tech. Note No. 3444, May, 1955, 60 pp.

Summation is presented of results obtained from friction and wear investigations. Results are consistent with theoretical predictions that solid surface films of low shear strength can serve to reduce both friction and surface damage. Films of graphitic carbon on cast irons, nickel oxide on nickel alloys and ferrous oxide and Fe_3O_4 on ferrous materials were found to be beneficial. Solid lubricants (molybdenum disulfide and graphite) are beneficial under severe operating conditions, including temperatures approaching 1000 degrees F; both materials are, however, subject to oxidation at these temperatures. Wear of materials such as Monel, Nodular iron, Nichrome V, Be-Ni, Discaloy, Inconel X, Refractaloy, Nimonic 80, and "L" Nik, sliding against hardened SAE 52100 steel without lubricant is shown graphically. Tables, photomicrographs, graphs and 48 references.—INCO. 9947

3.5.3.

Mechanism of Cavitation Inception and the Related Scale-Effects Problem. R. W. Kermeen, J. T. McGraw and B. R. Parkin. Paper before ASME, Internat. Mtg., Mexico City, March 10-12, 1954. *Trans. Am. Soc. Mech. Engrs.*, **77**, No. 4, 533-540; disc., 540-541 (1955) May.

An experimental investigation of incipient cavitation is described and relationship between these experiments and current theories is discussed. Experiments have indicated that cavitation number for inception varies with free-stream velocity and body size for both streamlined and bluff bodies. Preliminary studies of mechanism of cavitation were conducted in order to understand reasons for variations in cavitation performance. Photographic investigations disclosed effect of boundary layer on cavitation inception for both streamlined and bluff bodies. In addition, study has shown that tensions exist in flow of ordinary water at incipient cavitation. Graphs, photomicrographs, 20 references.—INCO. 10289

3.5.8

The Comet and Design Against Fatigue. W. J. Duncan. *Engineering*, **179**, 196-200 (1955) February 18.

Author was one of the three Assessors at the Court of Enquiry into the Comet accidents. After referring to the evidence presented and the findings of the Court, discusses fatigue under compound loading, effect of successive cycles of stress at different level, the size effect, "stress raisers" and design problems (shapes of cut-outs in pressure vessel, use of pretensionel bolts, safety margins).—BNF. 10053

3.5.8, 6.3.15

Research Points Way to New Methods of Preventing Galling and Seizing. E. S. Machlin. *Iron Age*, **175**, Nos. 6, 7, 91-93, 104-106 (1955) Feb. 10, Feb. 17.

Titanium's exceptional tendency to gall and seize is principally due to lack of formation of normal protective atmospheric film on metal's surface at room temperature. Protective oxide film can be formed by immersing titanium in hydrogen peroxide or heating in oxygen above about 800 degrees C. Oxidation of titanium at elevated temperature reduces friction coefficients of various metals on titanium. Measurements of friction coefficients of titanium containing various amounts of oxygen and nitrogen in solution were made. Values of friction coefficients (maximum) on surfaces formed in argon, tested in argon and then in air are tabulated. Decrease in coefficient on changing atmosphere from argon to air increases in magnitude in the order titanium, iron, silver, copper. Increasing the hardness of underlying titanium or iron should improve ability of their oxides to protect against seizure and wear. Tables, graphs, 10 references.—INCO. 9891

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3.5.8

Civil Aircraft Accident: Report of the Court of Enquiry into the Accidents to Comet G-ALYP and Comet G-ALYY. Ministry of Transport and Civil Aviation. Brochure, 1955, 48 pp. Available from: H. M. Stationery Office, England.

It is concluded that the cause of the accidents was structural failure of the pressure cabin due to fatigue, as suggested by water-tank tests on Comet airframes at the Royal Aircraft Establishment: the tests demonstrated fatigue failures originating at points of concentration of stress near the corners of "cut-outs" in the structure of the cabin for windows and hatches.—BNF. 10211

3.5.8, 3.5.3, 3.8.4

Analysis of the Effect of Various Factors on Metal Transfer and Wear Between Specimen Pairs of Same Metal and Same Shape. Part I. The Basic Scheme of Formulation of Metal Transfer and Wear. Part II. Effect of the Surrounding Atmosphere. I.-M. FENG. *J. Applied Physics,* **26,** No. 1, 24-27, 28-32 (1955) January.

Part I. Discusses mechanical, thermal and adhesion factors mathematically.

Part II. Effects of oxidation, absorption of gases and water vapor, etc., at the surfaces on metal transfer and wear; adhesion decreases with increasing oxide layer (the discussion is limited to the case where surface layer is thinner than average depth of roughening.—BNF. 9992

3.5.8, 5.5.3

Understressing As a Means of Eliminating the Damaging Effect of Fatigue Stressing. H. E. FRANKEL AND J. A. BENNETT. Paper before Am. Soc. Testing Materials, 58th Ann. Mtg., Atlantic City, June 26-July 1, 1955. ASTM Preprint No. 71, 1955, 9 pp.

Rotating-beam tests of heat-treated SAE 4340 steel (1.74% nickel) showed that the fatigue limit could be increased by coaxing. Damaging effect of fatigue stressing 10% above the fatigue limit was eliminated by understressing and coaxing. Damage produced by a stress 30% above the fatigue limit was not completely eliminated. Specimens coated with a rust preventive oil showed greater fatigue resistance than clean specimens. Tables, graphs and 8 ref.—INCO. 10002

3.5.8, 3.8.4, 3.5.3

Friction Between Unlubricated Metals: a Theoretical Analysis of the Junction Model. A. P. GREEN. *Proc. Roy. Soc., Ser. A,* **228,** 191-204 (1955) Feb. 22.

An elaboration of the theory of Bowden and Tabor (according to which friction is due to shearing of junctions formed by adhesion between minute asperities on the sliding surfaces) to give a clearer picture of the inception of the stresses and deformation in junctions. Includes some tests with plasticine models.—BNF. 10012

3.5.9, 3.8.4

Oxidation and Corrosion at Medium and Low Temperatures. (In German.) KARL HAUFFE. *Werkstoffe und Korrosion,* **6,** No. 3, 117-129; disc., 129-130 (1955) March.

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nickel steels is presented. Diagrams, graphs. 39 references.—BTR. 10066

3.5.8, 6.6.8, 6.5

Fretting Between Metals and Plastics. DANIEL CHAMBAUD. *Rev. Nickel*, **20,** No. 2, 30 (1954).

A steel axle showed fretting after a short time in contact with a rocking plastic bearing. A nickel plated axle showed no such fretting.—MA. 9292

3.6 Electrochemical Effects

3.6.5, 3.8.2

Electrode Potentials. Parts I, II. G. W. AKIMOV. Chapter III, "Theory and Research Methods of Metallic Corrosion" (Academy of Sciences, USSR, Moscow), 1945; translation: *Corrosion*, **11,** Nos. 11, 12, 477t-486t, 515t-534t (1955) November, December.

Characteristics of reversible and irreversible electrode potentials are defined with respect to the ionic patterns characteristic of the two states. Limits of ionic exchange are seen as significant in achievement of polarization of a metal surface. The theory of electrode potentials is considered at some length with pertinent mathematical derivations. Significance and characteristics of the double layer on a metal immersed in an electrolyte are reviewed with emphasis on ionic activity.

Theoretical and practical aspects of irreversible potentials are considered with respect to several metals and environments. Differences between the considerations affecting potentials of simple irreversible electrodes and complex electrodes are detailed in several liquid and gaseous environments. The effect of stress in lowering electrode potentials is covered, as are results of experiments in environments with oxidizers, chlorides and the effects of temperature, velocity of solution and time.

Potentials of active cathodes and anodes are discussed. Theoretical influence of films, current densities and direction and experiments with a copper-zinc couple are detailed. Uses of polarization diagrams are considered and the significance of anodic and cathodic control of a corroding system explained.

The author examines results of experiments with several complex alloys. The influence of the several components of the alloy is weighed and numerous cases involving different areas of cathode and anode and the difficulties involved in making experimental determinations of true potentials examined. Potentials of complex anodes of the film-pore type are determined by an experiment which includes a means of continuously cleaning the specimen of protective films. The nature and characteristics of films are covered as is the effect of varying thicknesses of film.

The effect of differences in lattice structure are investigated. Diagrams of potentials taken under varying conditions are given. 62 figures. Twelve tables. 10322

3.8 Miscellaneous Principles

Electrochemical Research on Ruthenium with Radioisotopes. Part I. Anodic Processes. (In French.) M. A. EL GUEBELY AND M. HAISSINSKY. *J. chim. phys.*, **51,** No. 6, 290-295 (1954) June.

Anodic oxidation of 0.02m trivalent $Ru(SO_4)_2$ in acid solution. Graph, diagram. 9 references.—BTR. 9512

3.8.2, 6.2.2, 4.3.3

Electrochemical Behavior of Iron in Hot Concentrated Solutions of Alkali. Parts I, II. (In German.) V. V. LOSEV AND B. N. KABANOV. *J. Phys. Chem. USSR* (Zhurnal Fizicheskoi Khimii), **28,** No. 5, 824-836, 914-925 (1954) May.

Capacitance of electrode during three processes. Effect of concentration of iron ions in solution on the anode process. Reversible nature of passivation of iron electrode. 25 references—BTR. 9570

3.8.2, 6.2.2, 6.3.8, 4.5.1

The Formation of Double Layers on Iron and Lead Electrodes in Soils. (In German.) TIHOMIL MARKOVIC AND P. KIRKOV. *Werkstoffe u. Korrosion*, **5,** No. 7, 241-243 (1954) July.

The formation of double layers on iron and lead electrodes in synthetic soils substitutes was followed by Hickling's method [*Trans. Faraday Soc.*, **36,** 394 (1939)]. When the soil was unsaturated (10 percent liquid), only the first part of the Helmholtz double layer formed on iron electrodes. Oversaturated soil (18 percent liquid) produced a layer similar to that formed in distilled water. On lead electrodes in clay soils, the layer formed as in electrolytes, but the capacity of the parts was greater than for the Helmholtz double layer. 4 references.—MA. 9561

5. PREVENTIVE MEASURES

5.3 Metallic Coatings

5.3.4

Electrodeposition of Gold Films of Greater Hardness. (In Russian). N. P. FEDOT'EV, N. M. OSTROUMOVA AND P. M. VYACHESLAVOV. *J. Applied Chem., USSR* (Zhurnal Prikladnoi Khimii), **27,** No. 1,

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43-50 (1954) Jan.; *J. Applied Chem. Abstracts*, **4**, ii-445 (1954) Oct.

Electrodeposition of gold from auric chloride solutions with additions of varying amounts of nickel as nickel cyanide is studied in order to obtain deposits of greater hardness and abrasion resistance. Deposits of the same color as pure gold and containing 0.32-0.40 percent nickel are obtained using an electrolyte of the following composition (in g per 1): 4 gold, 2 nickel, and 16 free potassium cyanide. Optimum conditions for obtaining deposits of 1.6 times greater microhardness and abrasion resistance are: temperature 70°, platinum anodes, and current density 2 amp per dm.²—INCO. 9407

5.3.4

Electrolytic Production of Ternary Alloys of Nickel with Iron and Molybdenum. (In Russian.) T. F. FRANTSEVICH-ZABLUDOVSKAYA, I. N. FRANTSEVICH AND K. D. MODYLEVSKAYA. *J. Applied Chem., USSR* (Zhur. Priklad. Khim.), **27**, No. 4, 413-420 (1954) April.

Bright deposits of nickel-iron-molybdenum alloys containing 53-81.5 percent nickel could be produced on copper (but not on stainless steel) from baths containing nickel sulfate, ferric sulfate, molybdenum trioxide, sodium citrate and sodium chloride.—BNF. 9682

5.3.4

Hardfacing by Submerged Arc Welding. KARL GERING *Schweissen und Schneiden*, **6**, No. 5, 183-192 (1954) May.

Repair and hardfacing of high alloy steel sintering drums and supporting rollers. Process and economy. Graphs, photographs, diagrams, table.—BTR. 9680

5.3.4

Electrodeposition of Tin Alloys. (In German.) J. W. CUTHBERTSON. *Schweiz. Arch. angew. Wiss. u. Techn.*, **20**, No. 5, 148-152 (1954).

The electrodeposition of alloys requires that the deposition potentials of the constituents shall be fairly close together and that the salts of the metals to be deposited shall have sufficient solubility in the electrolyte to permit adequate current density, while industrial application of such processes is possible only if the electrolyte is stable during storage and use. For tin alloys, these requirements are met by stannate solutions, the other constituent being present as a cyanide, or by complex fluoride (i.e., fluoborate or fluosilicate) solutions. Acid solutions have higher electrical conductivity and can be operated at higher current density; they are also more suitable for bright plating. Some alkaline solutions function efficiently only at elevated temperatures (~50°C), where they are subject to gradual oxidation. Tin-zinc alloys are plated from stannate-cyanide solutions, the zinc content being controlled by the amount of free sodium hydroxide in the electrolyte; alloy anodes can be employed. Tin-zinc electroplate is commercially employed for small steel components and can replace cadmium plate except under conditions of marine corrosion, where tin-cadmium alloy deposits have excellent corrosion-resistance. Two types of copper-tin alloys are plated, also from stannnate-cyanide solution: a red bronze with 10 percent tin and speculum metal with 43 percent tin. A complex chloride-fluoride solution of nickel and tin salts deposits the NiSn phase, irrespective, within wide limits, of the composition of the electrolyte; this phase is not formed below 50°C and is ther-

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modynamically unstable above 300°C. The tin-nickel plate is finding applications as a replacement for chromium plate on nickel undercoats. Tin-cobalt and tin-antimony alloys can be plated from similar solutions.—MA. 9582

5.3.4

Metallic Coatings on Steel. D. L. PHILLIPS. Iron and Steel Inst., Spec. Rept. No. 49, 1-8 (1954).

Investigations carried out at the Sketty Hall Labs, are described. In a new method for insuring a reactive steel surface the surface of cold-rolled strip is first oxidized in a slightly oxidizing atmosphere, and is then passed through a reducing atmosphere to produce a nascent or freshly formed sponge-Fe film brought in contact with the molten coating metal. The influence of steel composition on hot-dip galvanized behavior was examined by rotating rod or strip at speeds comparable with the speed through a galvanizing bath, in small bath of zinc, at definite times and temperatures. It was shown that carbon in steel increases the reaction between iron and zinc to form intermediate layers of iron-zinc alloy. Carbon had a maximum effect in the pearlitic condition, and a minimum effect as cementite or graphite. Alloy formation was increased by silicon, even in the absence of carbon. A steel containing 0.16 percent silicon, which had been completely decarburized by treatment in wet hydrogen, produced far more alloy than carbon-free iron containing no silicon. Phosphorus can produce an iron-zinc layer with a characteristic columnar structure, which may increase the adhesion. Steels containing aluminum as an alloy were more resistant to the formation of the iron-zinc layer. Both titanium and niobium yielded thin uniform coatings with a much reduced thickness of alloy layer. The reactivity of the steel base is greater in a strained or deformed condition, than in the annealed state. Tin and lead must both be present to produce large crystals or spangles of zinc on sheet. The rate of alloying between iron and molten aluminum is very fast, immersion of only a few sec. resulting in a thick, irregular, brittle layer. Adding up to 5 percent silicon or 0.6 percent beryllium reduces the amount and modifies the form of this alloy so that the

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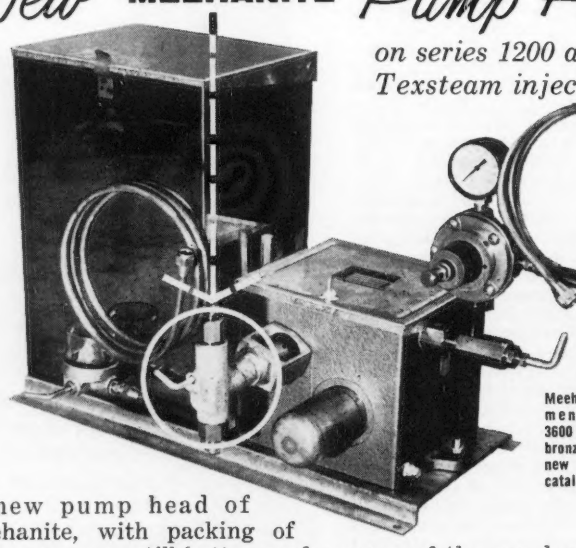

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composite coating becomes much more ductile.—EL. 9453

5.3.4

Electroless Plating Comes of Age. A. BRENNER. *Metal Finishing*, **52**, Nos. 11, 12, 68-76, 61-68 (1954) Nov., Dec.

Literature on electroless plating subsequent to 1947 is reviewed and available information on the present commercial utilization of the process is summarized. Main features of the process are reviewed including equipment used and bath compositions. Process is a controlled autocatalytic reduction of nickel or cobalt ion by hypophosphite ion on certain catalytic surfaces and results in the production of a sound, coherent coating of metal. Only nickel, cobalt, or nickel-cobalt alloys have been deposited by this process in a manner capable of practical application. General Amer. Transportation Co. has done the largest amount of research work in developing the process and they have named it "Kanigen." Tables, graphs, and 49 references.

5.3.4

Aluminized Coatings, A Comparison of Hot-Dip Coating With Aluminium and Hot Galvanizing. A. G. THOMSON. *Aircraft Eng.*, **26**, No. 306, 266 (1954) Aug.

The British Iron and Steel Research Association has studied the properties of hot-dip aluminized coatings, which has led to the development of a simplified process for coating steel or cast iron with aluminum offering possibilities

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for the protection of aircraft components. Samples received in 1944 by the Corrosion Committee of the Iron and Steel Institute (Atmospheric Corrosion Sub-Committee) have been tested, and the tests indicate that these coatings are highly resistant to atmospheric corrosion; this property is particularly marked in humid and sulfurous atmospheres in which zinc is liable to increased attack. Investigation of the properties of cold-reduced mild steel sheet, tube, angles, and rolled sections, up to 15 in. long when dipped into molten aluminum after various preliminary treatments show the process to be practical. Various aspects of aluminized coatings are considered and resistance to heat and corrosion, mechanical properties, and costs compared to hot dip galvanizing.—ALL. 9387

5.3.4

Electroless Nickel Plating. S. M. PANCHENKO AND M. A. KROKHINA. *Vestnik Mashinostroyenia,* No. 12, 68-70 **(1954)** Dec.; *Engrs.' Digest,* **16,** No. 3, 98-99 (1955) March.

Chemistry of electroless nickel plating process is discussed. Composition of solution is tabulated. As a result of observations, it is recommended that the process be conducted intermittently, with full utilization of the solution in each single cycle. Graphs and table.—INCO. 9624

5.3.4

Colorimetric Determination of Iron in Hard Chromium Plating Baths. (In German). H. POHL. *Metalloberflache,* Sec. B, **6,** No. 9, B129-B130 (1954) Sept.

Determination is carried out with potassium thiocyanate in presence of chromium trioxide using a Lange universal colorimeter. Claimed to be superior to gravimetric and volumetric methods. Iron contents up to 17g/1 can be determined in 10-15 minutes with a maximum error of 0.05g iron/1.—BNF. 9341

5.3.4, 3.6.8

The Behaviour of Zinc Anodes in Cyanide Baths. (In German.) WILLI MACHU, A. M. AZZAM AND G. M. HABASHI. *Werkstoffe u. Korrosion,* **5,** No. 4, 129-136 (1954) April.

The liability to passivity and corrosive attack of zinc anodes in various cyanide electrolytes is determined from the passivation time, obtained from current density/time curves and also from current density/potential plots. The initial percentage covering of the zinc and the specific passivation constant for electrolytes of various concentrations are tabulated. Free sodium cyanide and sodium hydroxide reduce the covering of the anode and increase its activity. Both methods of measurement indicate a high degree of polarization of zinc electrodes. The potential of the zinc cathodes becomes more negative as the concentration of free sodium cyanide is raised. It is concluded that this system represents a case of surface-layer polarization.—MA. 9565

5.3.4, 5.3.2

Copper-Tin Alloy Plating. W. H. SAFRANEK AND C. L. FAUST. Paper before Am. Electroplaters' Soc., 41st Ann. Conv., July 13, 1954. *Plating,* **41,** No. 10, 1159-1164, 1169-1170 (1954) Oct.

Process for plating with bronze or Speculum: Copper-tin alloy plates (17-50 percent tin, balance copper) are discussed in terms of leveling and corrosion resistance. Bronze plus a thin nickel plate performed better than thick nickel plate in outdoor marine atmosphere weathering tests and was at least as good as nickel plate in an industrial atmosphere. Bronze plus chromium was greatly superior to copper plus chromium. Bronze alloy is being considered as a replacement for nickel plate. Alloy plate that smoothens surfaces 40-66 percent/.001 in of plate is deposited from pyrophosphate bath. Tin content effects leveling power. Tables show characteristics of copper-tin alloy plating baths, leveling data, results of acetic acid salt spray tests on bronze plus bright nickel plus chromium plated bumper guards, results of exposing bronze plated steel panels to various outdoor atmospheres, comparison of Speculum with zinc and nickel plates on steel in weathering tests, and weight loss data on Speculum and nickel plates on steel. Photomicrographs, photographs of exposure specimens, 13 references.—INCO. 9301

5.3.4, 5.9.4, 1.6, 6.2.5

Research and Developmental Work on Corrosion Resistant Black Coatings Covering Stainless Steel. I. LAIRD NEWELL. Souther Engineering Co. Report 19 (Final), Section 1; U. S. Ordnance Corps., Contact DA-19-059-ORD-1028; ASTIA Document 28571 (Feb., 1954) 171 pp.

Thin black chromium coatings for stainless steels were obtained from plating solutions containing acetic acid and no sulfate at current densities of 1000-2000 amp per sq ft. Densities of this order, however, are presently impracticable for commercial plating. By altering the chemical composition of the bath, coatings having fairly good corrosion resistance and resembling phosphate coatings on carbon steel were obtained at current densities of the order used for hard chromium plating (250-300 amp per sq ft).

By making stainless steel parts cathodic in various standard types of zinc- and manganese-modified phosphating baths, gray-black electrophosphate coatings equivalent to chemical phosphate coatings on carbon steel were produced.

Of various proprietary methods and compounds, Ateenate was the only process that gave a thin black oxide coating which was satisfactory in appearance, abrasion resistance, and lack of buildup on threaded parts. Details of this process are not disclosed.

Attempts to produce black oxide coatings on stainless steels from molybdate, nickel-phosphide, nickel sulfamate, alkaline chloramine, and sodium bromate solutions were either unsuccessful or gave coatings of inferior quality and resistance to the processes described above.

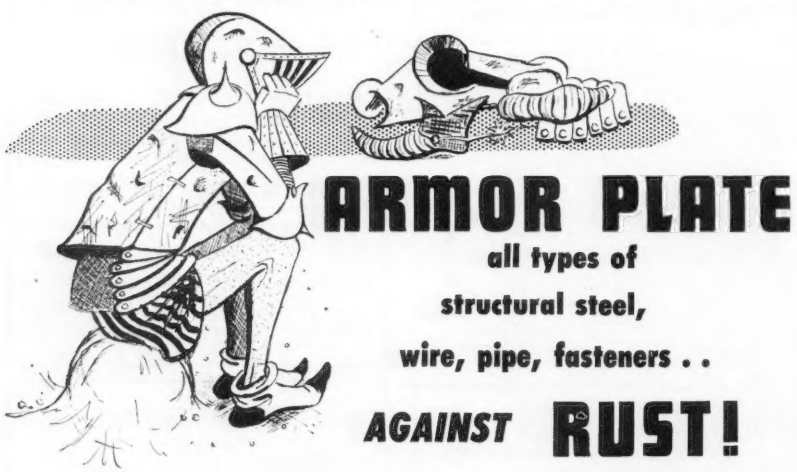
Results of salt spray and wear tests on the various coatings are given.—PDA. 9581

5.4 Non-Metallic Coatings and Paints

5.4.5

Paint and Plastics; Their Role in the Corrosion Problems Associated with Drainage and Water Treatment. D. FRANK AND N. STUTTERHEIM. *S. African Ind. Chemist,* **8,** No. 4, 64-66 (1954); *Peintures, Pigments, Vernis,* **31,** No. 1, 54 (1955).

The nature of the material requiring protection, the corrosive medium, and available methods of treatment are considered. It is concluded that while plastics offer excellent protection and durability, the difficulties of manipulation and application often render the use of paint preferable.—RPI. 9689



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5.4.5
Adherence of Paint Films. E. G. BOBALEK. *Metal Progress,* **66,** No. 2, 113-118 (1954).

A general review of the definition of adhesion, the effect of thinners, humidity, wetting properties, film shrinkage and the nature of the pigment.—EL. 9306

5.4.5, 1.6
Organic Finishing Handbook. Book, 4th Edition, 1954, 298 pp. Finishing Publications Inc., 381 Broadway, Westwood, N. J.

This handbook has sections dealing with raw materials (solvents, resins, etc.), types of finish, methods of application, coating evaluation, safety hazards and reference data. The individual chapters include "The Preparation of Metals for Paint" and "Chemical Resistant Coatings."—BNF. 9683

5.4.5, 1.6, 2.3.7
Fundamentals of Organic Coating Technology. A. V. BLOM. Book, 1954, 385 pp. Verlag Birkhauser, Basle/Stuttgart.

In 1949 Dr. Blom, an international authority who until recently directed the Organic Coatings Department of the Swiss Materials Testing Station in Zurich, published his English-language book "Organic Coatings in Theory and Practice." The present work is a German-language version in which the text has been enlarged and brought up-to-date and this book is now undoubtedly one of the most important on its subject. After an introduction dealing with the general chemistry and physics of paints, the author deals with each of the major materials and synthetic constituents of paints individually. The following sections are devoted to chemical and physical aspects of coating formation and the mechanism of deformation. The final section deals with paint application and testing. This is possibly the weakest of the sections for the theory and protective function of paint is rather sketchily dealt with as are also, for instance, the practical methods for abrasion and adhesion testing.—EL. 9361

5.4.5, 7.7
Non-Metallic Jackets Given Soak, Voltage Test in Search for Cable Sheath Materials. *Corrosion* (Technical Committee News), **10,** No. 10, 12 (1954) Oct.

Results of resistance measurements made on aluminum, iron and lead wires coated with non-metallic jackets of materials designed to protect cable sheaths against corrosion have been tabulated. The wires were first covered with 38 to 50 mils of different jacket materials and then soaked in water and dilute solutions under various conditions of temperature and applied voltage. All three metals were completely protected by neoprene jackets for over 400 days at room temperatures, using 1½ volts dc. Raising the voltage greatly accelerated the rate of deterioration. Samples with 90 volts dc positive applied to conductors were more stable than samples with 90 volts dc negative. Samples covered with an ordinary grade of neoprene jacket failed first, while those covered with a moisture-resistant grade of neoprene jacket lasted longer. In most cases the jackets failed first over lead although the jacket walls were actually thicker over lead than over aluminum. Samples for soak tests at 158°F protected with polyethylene and polyvinylchloride showed no signs of failure in 10 months with 90 volts applied across the jacket. Soak tests are described. It was found that

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many adhesive coated plastic insulating tapes are vulnerable to low dc voltages.—ALL. 9411

5.4.2

Adhesive and Protective Characteristics of Ceramic Coating A-417 and Its Effect on Engine Life of Forged Refractaloy 26 (AMS 5760) and Cast Stellite 21 (AMS 5385) Turbine Blades. FLOYD B. GARRETT AND CHARLES A. GYORGAK. U. S. Nat'l. Advisory Committee for Aeronautics, Research Memo. E52L30, 1953 (unclassified 1954), 21 pp.

Refractaloy 26 (a forged nickel-iron-chromium-base alloy of relatively low-temperature corrosion-resistance) and Stellite 21 (an investment-cast cobalt-chromium-base alloy of satisfactory corrosion-resistance) were coated with N.B.S. A-417, fired at 1850°F (1010°C), and engine-tested at 1500°F (815°C) and 20,500-21,300 lb/in² max stress. Coating adhered well to both alloys, decreased their high-temperature corrosion, and did not affect their engine lives. The composition of N.B.S. A-417 is: 70 percent Frit 331, 30 percent chromic acid, 5 percent enameller's clay, and 48 percent water. Frit 331, computed as oxide composition, consists of 38.0 silicon dioxide, 44.0 barium oxide, 6.5 percent boron oxide, 4.0 percent calcium oxide, 2.5 percent beryllium oxide, and 5.0 percent zinc oxide. It is prepared by smelting at 2425°F (1330°C) a mixture of silicon dioxide, barium carbonate, orthoboric acid, calcium carbonate, beryllium oxide, and zinc oxide.—MA. 9675

5.4.2, 2.3.7

Abrasion Resistance of Some Dry-Process Enamels. W. C. SPANGENBERG. Metal & Thermit Corp. Paper before Am. Ceram. Soc., 55th Ann. Mtg., New York, April 27, 1953. *J. Am. Ceram. Soc.*, **37,** Pt. I, No. 2, 48-51 (1954) Feb. 1.

Resistance to abrasion of some dry-process cast-iron enamels was investigated using the new weight-loss method of testing abrasion resistance now under development by the Porcelain Enamel Institute. Test differentiated between surface and subsurface abrasion resistance. Data obtained on eight commercial cast-iron enamels showed the general superiority of acid-resistant enamels compared with non-acid-resisting compositions. It was found that long smelting times and small additions of Sn oxide improve the abrasion resistance. Tables, graphs and 5 references.—INCO. 9385

5.8 Inhibitors and Passivators

5.8.1

Corrosion Inhibitors. Part I. Principles of Inhibition. Part II. Inhibitors in Practice. L. L. SHREIR. *Corrosion Technology,* **1,** Nos. 6, 8, 200-203, 291-294 (1954) Aug., Oct.

Part I Mechanism of inhibition in aqueous neutral solutions. Part II. Factors influencing choice of inhibitor; characteristics of common inhibitors; water treatment. 9330

5.8.2

Inhibitors of Atmospheric Corrosion. (In Russian). S. A. BALEZIN AND V. P. BARANNIK. *Doklady Akad Nauk S.S.S.R.,* **95,** No. 2, 345-347 (1954) March 11.

Of the substances investigated as vapor phase inhibitors for carbon steel, the most effective were found to be the benzoates and carbonates of amino-alcohols. Table, micrographs, 4 references.—BNF. 9340

5.8.2, 4.4.7

Corrosion of Steel in Contact with Aqueous Solution of an Electrolyte, Containing Added Sodium Nitrite, and Liquid Fuel. I. V. KROTOV AND V. V. KLUBOVA. *J. Applied Chem., U.S.S.R.* (Zhurnal Priklad. Khim.), **27,** 201-206 (1954).

Experiments described and amount of sodium nitrite needed to stop corrosion of steel in contact with dstilled water-fuel (aviation and cracked gasoline, kerosine), and 3 percent aqueous sodium chloride solution-cracked gasoline established. Corrosion at synthetic sea water-fuel interface also studied and remedial steps suggested. Translation available: Assoc. Tech. Services, Box 271, East Orange, N. J.—ATS. 9479

5.8.2, 8.4.3

Inhibitors Checked at Wellhead. D. R. FINCHER. Tide Water Assoc. Oil Co. *World Oil,* **139,** No. 7, 200, 202-203 (1954) Dec.

Treatment of gas condensate wells with organic polar inhibitors at one of Tide Water's gasoline plants frequently resulted in emulsification of the condensate with the small amount of connate water usually produced, which interfered with operations to such an extent that the continued use of inhibitors would be impractical. A test for the selection of inhibitors which eliminate the emulsion problem is described. A sample of produced condensate and water from a reservoir is mixed with the inhibitor and tested in a sample pot under wellhead pressure. The test was made in other oil fields to eliminate the necessity of using emulsion breaking compounds.—INCO. 9681

5.8.3

Contribution to the Study of Inorganic Inhibitors. (In Italian.) U. BERTOCCI. *Metallurgia italiana,* **46,** special supplement to No. 5, 64-65; disc., 65-66 (1954) May.

Influence of arsenic, antimony, and tin on the attack of metals of the iron group by hydrochloric acid solutions. Charts. 12 references.—BTR. 9510

5.9 Surface Treatment

5.9.2

A Survey of Metal Surface Soils and Their Removal. E. ENGEL. *Org. Finishing,* **15,** No. 6, 18-23 (1954) June.

Surveys the lubricants, coolants, drawing compounds etc. which have to be removed from metal parts after manufacture and compares the efficiencies of cleaning methods used, e.g. solvents, vapor degreasing, alkali cleaning, etc.—BNF. 9632

5.9.2

Chemical Polishing. (In German). H. SPAHN. *Metalloberflache,* Sec. B, **6,** No. 2, B17-B26 (1954) Feb.

Considered in respect of practical application. Composition of chemical polishing baths (aluminum and alloys, copper and alloys); theory of chemical polishing; practice (adjustment of baths with particular reference to water content, effect of temperature and duration of polishing on brightening, properties of chemically polished surfaces and possibilities of application, comparison (reflectivity with other polishing methods). Refers mainly to German work.—BNF. 9383

5.9.2, 3.2.2, 6.3.15

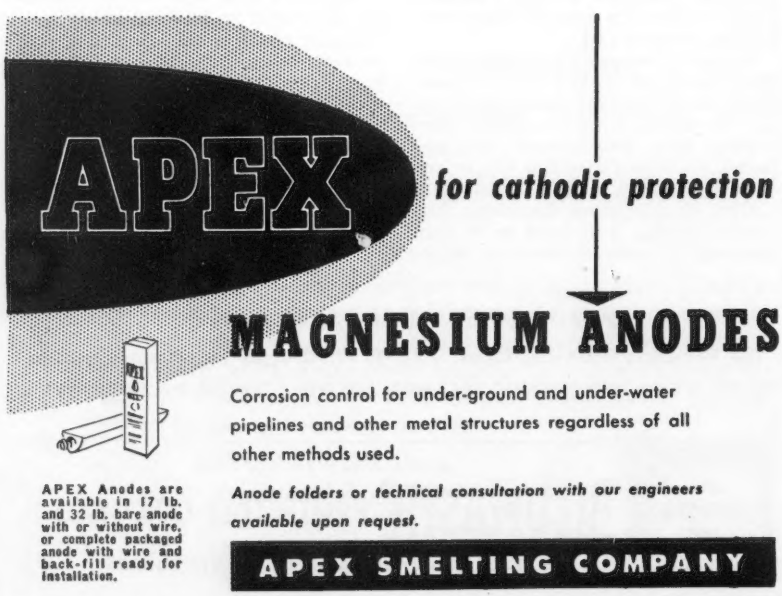
How to Avoid Titanium Embrittlement During Pickling. H. B. BOMBERGER, M. B. VORDAHL AND W. L. FINLAY. *Materials and Methods,* **40,** No. 6, 105 (1954) Dec.

Hydrogen embrittlement in the normal 10 percent nitric acid-2 percent hydrofluoric acid solution was investigated. Hydrogen uptake increases rapidly at decreasing nitric acid concentration below 20 percent (wt.). The reaction $3Ti + 4HNO_3 + 12HF \rightarrow 3TiF_4 + 8H_2O + 4NO$ is proposed. Preferred pickling solution contains 30 percent nitric acid—20 percent hydrofluoric acid.—EL. 9316

5.9.2, 6.3.15, 6.2.5

Descaling Process for Titanium and Stainless Steel. B. CHAMBERS. *Western Metals,* **12,** No. 9, 64-65 (1954).

A pre-anneal coating of a carbonate-nitrate mixture is applied to titanium.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The carbonates are believed to convert the normal scale oxides or the higher oxides produced by the nitrate into a non-adherent titanate form removable by gentle rubbing and a single brief pickle in a modified conventional nitric acid-hydrofluoric acid pickling solution. Stainless is coated with a silicon-bearing substance which decomposes in the furnace to give a coating of finely divided silicon dioxide which inhibits oxidation. The scale can be picked off in 2-4 min. following the usual heat-treatment.—EL. 9291

5.9.3

Belt Polishing or Wheel Polishing. Part VI. (In German.) G. PAHLITZSCH AND H. WINDISCH. *Metalloberflache*, Sec. A, **8**, No. 12, A180-188 (1954).

In this installment the authors summarize their recommendations for polishing practice. The type of abrasives suitable for each metal are tabulated. Wheel polishing is preferable where complicated shapes, recesses or edges, scale, hard casting skin, are dealt with or where the initial finish is relatively high (>240 grade. Belt polishing is preferable where parts with a finish corresponding to under 220 grade emery are to be dealt with, particularly on flat surfaces. The largest savings are obtained with aluminum copper, brass and bronze. Belt polishing is useful also for parts difficult to polish on the wheel such as finger holes in scissors, fork prongs, etc., automatic polishing, where the decrease in wheel diameter is unfavorable.—EL. 9579

5.9.4

Regeneration of Electropolishing Solutions for Steel. N. P. FEDOT'EV, E. G. KRUGLOVA AND S. YA. GRILIKHES. *J. Applied Chem., USSR* (Zhur. Priklad. Khim.), **27**, No. 2, 157-165 (1954).

Investigation into causes of deterioration of electrolytic polishing baths for steel having an approximate composition of 64 phosphoric acid, 14 sulfuric acid, and 6 chromium trioxide, and development of methods for adjusting and regenerating such baths, for maintaining their composition constant (chiefly by oxidizing the trivalent chromium) within definite limits until the permissible iron content is exceeded, and thereafter, for removing the iron from the electropolishing bath. Causes of inactivation, process of oxidation of trivalent chromium, effect of anode material and of solution composition thereon, and optimum conditions for insuring a quantitative oxidation of chromic oxide were studied. Regeneration of spent baths, reduction of sexivalent chromium and of ferric iron, precipitation of ferrous sulfate, and effect of cathode current density are considered. Favorable conditions for regeneration of electropolishing baths are proposed. Graphs, tables, four references.—INCO. 9645

5.9.4

Behaviour of Silver Anodes in Cyanide Baths. (In German.) M. S. EL-ANSARY AND A. M. AZZAM. *Werkstoffe u. Korrosion*, **5**, No. 8/9, 301-308 (1954) Aug.-Sept.

Investigation of the quantitative effect of constituents of the potassium cyanide bath during passivation experiments in the various electrolytes used in practice. Passivation experiments in potassium cyanide solutions; effect of potassium cyanide in potassium-silver cyanide solutions on passivity; and of potassium carbonate. Potential-time curves for the passivation process.—BNF. 9489

5.9.4

Causes of Defects in Phosphate Coatings. E. WAGNER. *Mitteil. Forsch.-Ges. Blechverarbeitung*, No. 7, 79-82 (1954).

Possible faults in the various stages of activated hot phosphating, using zinc phosphate solutions, and hints for avoiding them. Alkali cleaning incompleteness; dried-out solution; entrained alkali. Pickling: insufficient pickling; carry-over; capillary spaces containing residual alkali or acid. Phosphating bath; too hot; too cold; dried-out; sludge level level too high; presence of copper or aluminum in bath. Rinse bath; carry-over into rinse bath; contamination; too old; dried out. Drying: too slow; closed drying chambers; finger-prints. Storage of phosphated work under adverse conditions. Oils. Painting of phosphate coatings. (Translation available from Henry Brutcher, P. O. Box 157, Altadena, Calif.) 9391

5.9.4, 2.2.7

Corrosion Resistance of Carbo-Nitrided Steel. P. A. CLARKIN AND M. B. BEVER. *Metal Progress*, **66**, No. 6, 108-109 (1954) Dec.

Summary of an exploratory investigation in which the corrosion resistance of a carbo-nitrided steel, AISI 1018, was determined in an aqueous solution of 3 percent sodium chloride and in fresh, flowing sea water. Sea water tests were conducted by INCO at Kure Beach. Carburized specimens were tested for comparison. Case hardening was done from 1400° to 1700°F in various atmospheres containing 3-5 percent methane and 0-15 percent ammonia, the balance being carrier gas. After carbo-nitriding under conditions which do not lead to formation of a compound surface layer, plain car-

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bon steel corrodes in aqueous sodium chloride solution at the same rate as after carburizing. The presence of a compound layer at the surface, resulting from carbo-nitriding at low temperatures with high ammonia concentrations, markedly improves its resistance. Sea-water tests suggest that the compound layer may be undesirable in sea-water exposure long enough to penetrate the case. Illustrations.—INCO. 9417

5.9.4, 3.7.3

Thermo-Chemical Treatment of Steel in Molten Salts Containing Titanium. (In Polish). ROMAN SKORSKI. *Prace Inst. Mech.*, **4**, No. 12, 23-35 (1954).

The effect of baths containing sodium carbonate and 5-70 percent titanium dioxide on the surface structure of Armco iron and steel specimens treated at 850°-980°C, with and without addition of powdered charcoal to the bath, was investigated under various conditions of temperature, time, and chemical composition, and using various crucible materials. As a result of the treatment, the specimens were covered by corrosion-resistant layers containing up to 5 percent titanium. The carburization of the surface proceeded quicker and deeper than with other kinds of bath, and the surfaces showed a remarkably fine-grained structure even after treatment at 900°-1000°C. Owing to the very good wetting of the metallic surfaces by sodium carbonate-titanium dioxide baths, the salts penetrated well into all the surface cracks and pores, strengthening the structure of the specimen and accelerating the diffusion of carbon and titanium into the bulk of the metal.—MA. 9375

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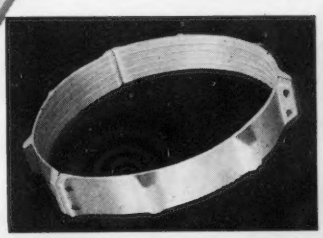

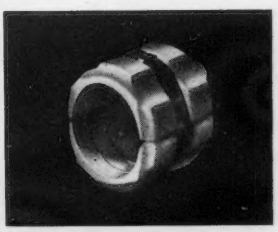

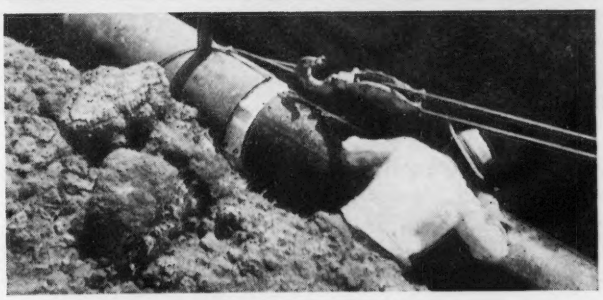

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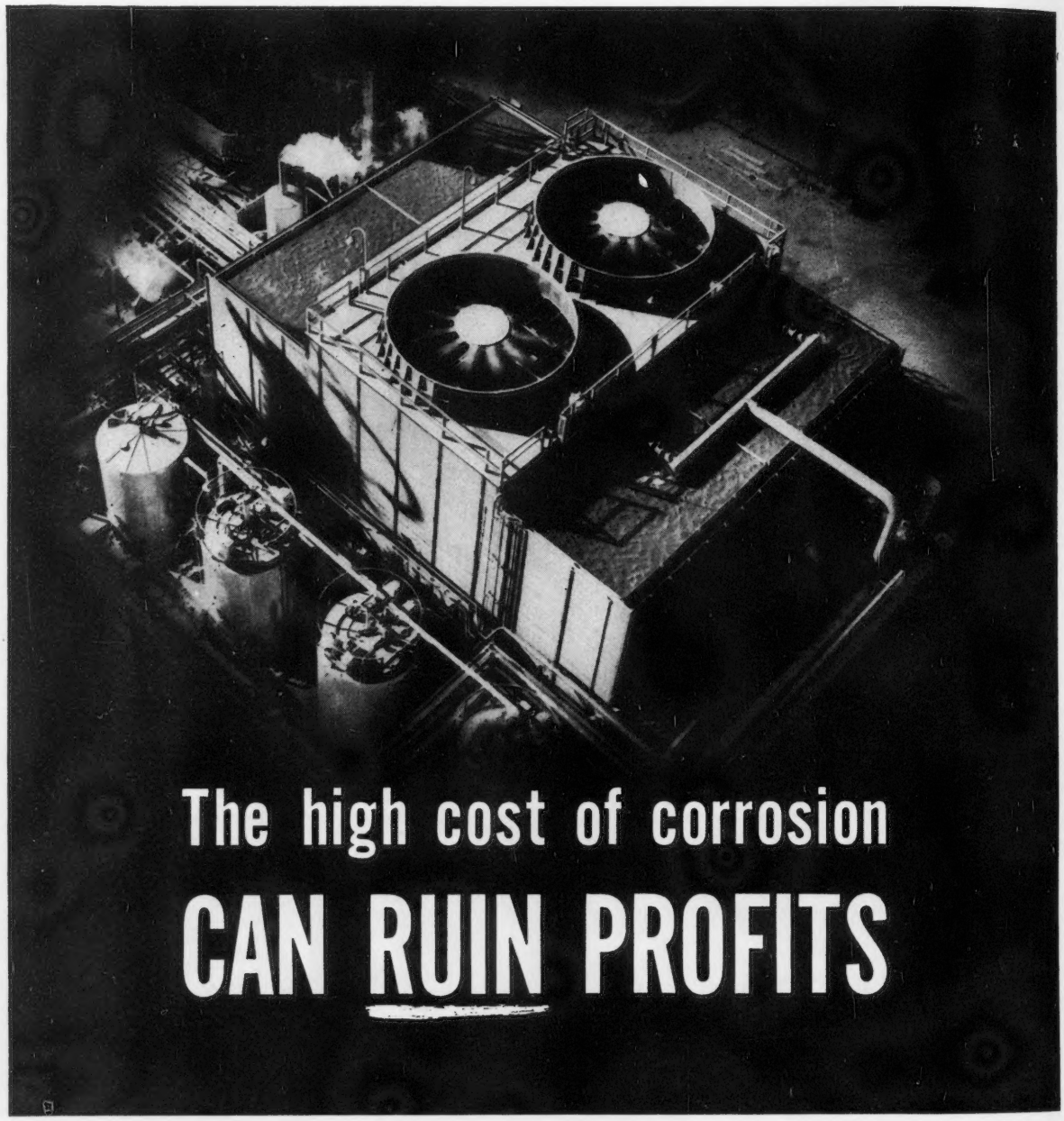

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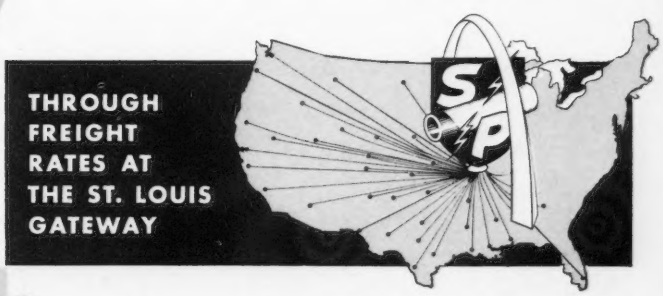

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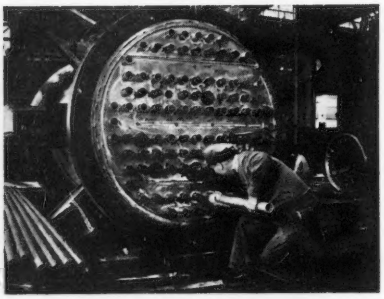

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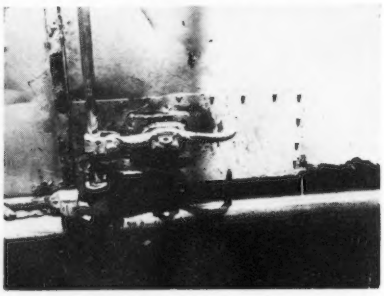

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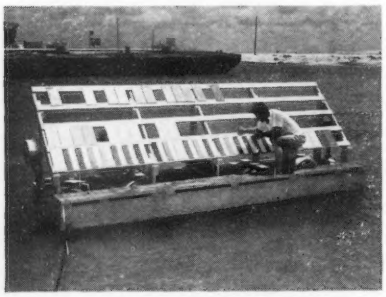

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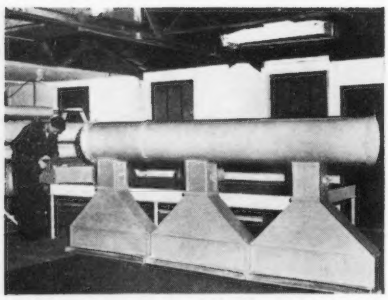

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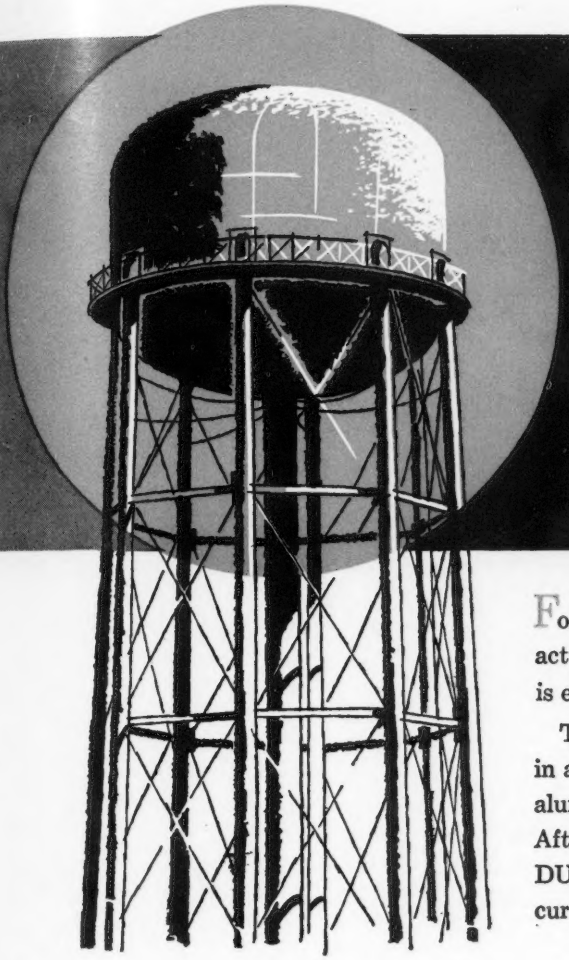

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